Alaska Gasline PORT AUTHORITY

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Application, Appendix A-B

Binder 1

AGIA License Application
November 30, 2007

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CERTIFICATION

I certify that I am authorized to submit this Application on behalf of the Alaska Gasline Port Authority ("Applicant").

I also certify that Applicant and any and all successors and assigns agree that in the event Applicant is awarded an AGIA License it will: (1) comply with AGIA and its requirements in their entirety, AS 43.90 *et seq.*, as in effect on June 8, 2007, (2) perform all of the actions and fulfill all of the Required and Additional Commitments listed in its Application and as required in Appendix D; (3) be bound by the License terms and conditions as set forth in Section 4 of the Request for Applications, and (4) abide by, in addition to AGIA, all other applicable laws, rules and regulations. This certification includes Applicant's agreement to act Promptly and Diligently in fulfilling all of the foregoing requirements, commitments, and other obligations.

In addition, I certify under AS 43.90.130(16) that by submitting this Application, Applicant has waived the right to appeal the rejection of its Application as incomplete, the issuance of a License to another applicant, or the Determination under AS 43.90.180(b) that no Application merits the issuance of a License.

Finally, I certify that the Applicant agrees this certification is provided by Applicant as consideration for the inducements provided to Applicant under AS 43.90.110, and that this certification shall remain binding upon the Applicant.

ALASKA GASLINE PORT AUTHORITY

By: ______________________
Jim Whitaker, Chairman

Subscribed and sworn to before me this 29th day of November, 2007.

CAMELLA S. MOTAS NOTARY PUBLIC STATE OF ALASKA

Camella S. Motas
Notary Public in and for Alaska
My Commission Expires: 4-24-10

Application for the All-Alaska Gas Line Project

Submitted by the Alaska Gasline Port Authority

to State of the Alaska Department of Revenue

for the Issuance of a License

Pursuant to the Alaska Gasline Inducement Act (AS 43.90)

November 30, 2007

Table of Contents

1. Executive Summary ... 1
1.1 The Alaska Gasline Port Authority ... 1
1.2 The Project ... 1
1.2.1 Pipeline ... 2
1.2.2 Liquefaction and Liquids Extraction Facilities ... 2
1.2.3 Gas Conditioning Plant ... 3
1.3 Substantial Permitting Progress for All Alaska Gas Line ... 3
2. Introduction to the Alaska Gasline Port Authority ... 4
2.1 Formation and History ... 4
2.2 Objectives of the Alaska Gasline Port Authority ... 4
2.3 Over Thirty Years of Public Support for the All-Alaska Gasline Project ... 6
3. Project Description ... 8
3.1 Introduction ... 8
3.2 Pipeline ... 10
3.2.1 Route ... 10
3.2.2 Technical Parameters ... 10
3.2.3 Receipt and Delivery Points, Major Markets Served ... 10
3.3 Gas Conditioning Plant ... 12
3.4 LNG Facilities in Valdez ... 13
3.5 Marine Transportation for LNG and NGL ... 13
3.5.1 LNG Tanker Transportation ... 13
3.5.2 LPG Tanker Transportation ... 14
3.6 Gas Processing and NGL Markets ... 15
4. Development Plan ... 17
4.1 Front End Engineering Design Plan ... 17
4.2 Stakeholder Issues Management Plan ... 17
4.2.1 Introduction ... 17
4.2.2 Land-Based Interests ... 19
4.2.3 Recreation, Aesthetics, and Wilderness ... 20
4.3 Commercial Plan for Pipeline ... 24
4.3.1 Plan Prior to Open Season ... 24
4.3.2 Plan for Open Season ... 26

4.3.3 Precedent Agreements ... 27
4.3.4 Proposed Services and General Tariff Terms ... 27
4.3.5 Rate Structure and Supporting Information ... 28
4.3.6 Alternative Ratemaking Methods and Incentives ... 28
4.3.7 Negotiated Rates ... 28
4.3.8 Anchor Shipper Incentive Rates and Commitments to Rates for Expansion Capacity ... 29
4.3.9 Commitments to In-State Service ... 29
4.3.10 Commitment on Rate Treatment of State's Reimbursement ... 32
4.3.11 Minimizing the Effect of Cost Overruns on Rates ... 32

4.4 Commercial Plan for the GCP ... 33

4.4.2 GCP Participation Agreement ... 33
4.4.3 GCP Project Transfer Agreement ... 34
4.4.4 Gas Processing Agreements ... 34
4.4.5 GCP Operations and Maintenance Services Contract ... 34

4.5 Commercial Plan for the LNG Facilities ... 35

4.5.2 LNG Participation Agreement ... 36
4.5.3 LNG Project Transfer Agreement ... 37
4.5.4 Liquefaction and Processing Services Agreements ... 37
4.5.5 Gas Sales and Purchase Agreements ... 37
4.5.6 LNG Operations and Maintenance Services Contract ... 38

4.6 Commercial Plan for Marine Transportation Services ... 38

4.7 Destination Markets for LNG and NGL ... 42

4.8 Plan for NGL Processing and NGL Markets ... 44

4.9 Regulatory Plan ... 45

4.9.1 Regulatory Approvals ... 45
4.9.2 Rights-of-Way ... 47
4.9.3 Commitments for FERC-Certificated Project ... 47
4.9.4 Commitments for RCA-Certificated Project ... 49

4.10 Local Project Headquarters Plan ... 50

5. Execution Plan ... 51

5.1 Project Execution Plan ... 51

5.2 Capital Cost Management Plan ... 51

5.3 Project Labor Agreement ... 51

5.3.1 Alaska Hire ... 52

6. Operations Plan ... 54

6.1 Expansion ... 54

6.1.1 Market Assessment ... 54
6.1.2 Expansion Terms ... 55
6.1.3 Rolled-in Rates Commitment ... 55

6.1.4 General Expansion Provisions 56

7. Project Cost Estimate 57

7.1 Cost Estimate for Development Phase 57

7.2 Cost Estimate for Execution Phase 57

8. Project Schedule 59

8.1 Schedule for Development Phase 59

8.2 Schedule for Execution Phase 59

9. Risk Assessment and Mitigation 60

9.1 Open Season and Firm Transportation Commitments 60

9.2 North Slope GCP 60

9.3 Permits for LNG Export, Shipping, Import 60

9.4 Availability and Costs of Labor Resources and Construction Equipment 61

9.5 Rights-of-Way Acquisition and Environmental Requirements 61

9.6 Federal Loan Guarantee and Debt Financing 61

9.7 Certificate Authority from the Applicable Jurisdictional Agencies 63

10. Financial Plan 64

10.1 Description of Applicant and Participating Entities 64

10.2 Demonstration of Financial Resources and Financing Plan Approach 64

11. Performance History and Project Capability 65

12. Project Economic Viability 66

12.1 Target Markets for LNG and NGL 66

12.1.1 East Asian LNG Markets: Demand and Supply 67
12.1.2 Price-Setting Mechanisms in the East Asian LNG Markets 70
12.1.3 LNG Price Assumptions 73
12.1.4 Comparison of E. Asian LNG Markets with N. American Gas Markets 76
12.1.5 Target LPG Markets 80

12.2 Project Costs 84

12.3 Netback Prices and Revenue 84

12.4 Cash Flows to the State of Alaska 84

12.5 Competitive Analysis 84

13. Project Technical Viability 85

14. Proposed Reimbursement 86

15. Former Point Thomson Unit 87

List of Figures and Tables

Figure 1 Project Facilities Map 9
Figure 2 Cook Inlet Historic and Project Natural Gas Consumption 11
Figure 3 GCP Commercial Structure 33
Figure 4 LNG Facilities Commercial Structure 36
Figure 5 Indicative Time Charter Structure (DES Basis) 39
Figure 6 Marine Transportation Development Process 40
Figure 7 Construction Schedule of an LNG Vessel 41
Figure 8 Marine Transportation Cost Components 41
Figure 9 Global LNG Imports 2006 (bcm) 67
Figure 10 LNG Demand Growth in East Asia (Low Growth Scenario) 69
Figure 11 LNG Demand Growth in East Asia (High Growth Scenario) 69
Figure 12 Historical Japan DES LNG “S-Curve” Formula 72
Figure 13 EIA Price Forecast for Imported Crude Oil (2007 dollars) 74
Figure 14 Assumed E. Asian LNG Prices (based on EIA oil price forecast) 75
Figure 15 NYMEX Light Sweet Crude Futures (November 19, 2007) 76
Figure 16 Historical Henry Hub and WTI Prices 77
Figure 17 Henry Hub Price as a Percentage of Oil Price 78
Figure 18 Henry Hub Price as Percentage of Oil Price (EIA forecast) 79
Figure 19 Forecast E. Asian LNG prices as Percentage of Oil Price 80
Figure 20 Historical Propane Prices 81
Figure 21 Relationship Between Japan Propane and US Imported Crude Oil 82
Figure 22 Historical Mont Belvieu Propane and Correlation 83
Figure 23 Historical Edmonton Propane and Correlation 83

Table 1 Regasification Capacity in Japan, South Korea and Taiwan 42
Table 2 Major Permits Required for the Project 45
Table 3 DOE Forecast of Economic Results for Point Thomson 89

List of Appendices

Alaska Gasline Port Authority
AGIA License Application
November 30, 2007

Appendix A	**Application Checklist**
Appendix B	**Glossary of Selected Terms and Abbreviations**
Appendix C	**Alaska Gasline Port Authority Formation Documents**
Appendix C - 1	City of Valdez Ordinance No. 99-11
Appendix C - 2	Fairbanks North Star Borough Ordinance No. 99-059
Appendix C - 3	North Slope Borough Ordinance Serial No. 99-06; Title 4: Alaska Gasline Port Authority
Appendix D	**Resolutions of Support from Alaskan Municipalities**
Appendix E	**Resolutions of Support from Alaska Municipal League**
Appendix E - 1	Alaska Municipal League Resolution 2004-11 Encouraging the Building of an All Alaska Gasline
Appendix E - 2	Alaska Municipal League Resolution #2005-09 in support of AGPA
Appendix E - 3	Alaska Municipal League Resolution No. 2007-15 Urging the Legislature to Approve a Contract to Construct an All-Alaska Natural Gas Pipeline
Appendix F	**Dittman Research Corporation Poll re AGPA Project May, 2005**
Appendix F - 1	CRG Research Poll regarding AGPA Project, May, 2005
Appendix G	**Permits and Authorizations**
Appendix G - 1	FERC Declaratory Order Yukon Pacific Corporation, 39 FERC ¶ 61,216 (1987).
	FERC Order Denying Rehearing 40 FERC ¶ 61,164 (1987)

Appendix G - 2 Presidential Finding Concerning Alaska Natural Gas, dated January 12, 1988

Appendix G - 3 Coastal Zone Consistency Determination

Appendix G - 4 TAGS Project-Wide Final EIS

Appendix G - 5 Ahtna Corporation Right of Way Agreement [Confidential]

Appendix G - 6 Federal Pipeline ROW Grant

Appendix G - 7 State of Alaska Conditional ROW Lease

Appendix G- 8 Yukon Pacific Corporation, DOE Opinion and Order No. 350 "Order Granting Authorization to Export Liquefied Natural Gas From Alaska" 1 FE ¶ 70,259 (11-16-1989)

Appendix G - 9 DOE/FE Opinion and Order No. 350-A, "Order Denying Rehearing Requests and Modifying Prior Order for Purposes of Clarification" 1 FE ¶ 70,303 (03-08-1990).

Appendix G - 10 Yukon Pacific LNG Project, Final EIS, FERC (Also see bound copy at Appendix Y above)

Appendix G - 11 Yukon Pacific Company L.P., "Order Granting NGA Section 3 Authorization for the Siting, Construction, and Operation of LNG Facility" 71 FERC ¶ 61,197 (1995) "Order Denying Rehearing" 72 FERC ¶ 61,226 (1995).

Appendix G- 12 Anderson Bay LNG/MT Facility Air Quality (PSD) Permit

Appendix G – 13 TAGS Permits White Paper dated January 21, 1999

Appendix H **Preliminary Draft of Precedent Agreement for Firm Natural Gas Transportation Service**

Appendix I **Pipeline Alignment Sheets, Revision 4.1, May/ June 2003 [Confidential]**

Appendix I - 1 TAGS Alignment Sheets, Revision 4.1, June 20, 2003 [Confidential]

Appendix I - 2 TAGS Alignment Sheets, Vol. I of IV, 001-035 [Confidential]

Appendix I - 3 TAGS Alignment Sheets, Vol. II of IV, 036-070 [Confidential]

Appendix I - 4 TAGS Alignment Sheets, Vol. III of IV, 071-105 [Confidential]

Appendix I - 5 TAGS Alignment Sheets, Vol. IV of IV, 106-141 [Confidential]

Appendix I - 6 TAGS Revision 4.1 Alignment Sheets June 20, 2003

Appendix J Land Ownership Along Project Route

Appendix J - 1 Land Status Along Proposed TAGS Route, Appendix F of Trans-Alaska Gas System Draft Environmental Impact Statement, September 1987

Appendix J – 2 TAPS Right of Way Map Showing Land Ownership

Appendix K Marine Transportation Cost Estimate [Confidential]

Appendix L Teaming Agreement between the Port Authority and BGT Limited, BLNG Inc., and Mitsui O.S.K. Lines, Ltd. [Confidential]

Appendix M Mitsui O.S.K. Lines' LPG Shipping Business

Appendix N IRS Tax Exempt Status Documents

Appendix N - 1 Application to IRS for Tax Exempt status

Appendix N - 2 Approval letter from IRS dated January 24, 2000 conferring tax exempt status

Appendix O Dr. Pedro van Meurs Memo dated March 30, 2000.

Appendix P Indicative Recourse Rate Calculation

Appendix Q Price Assumption Data Tables

Appendix R	**Alaska Statute 29.35.600 – 730 (Municipal Port Authority Act)**
Appendix S	**Letter of Interest from KitimatLNG, November 15, 2007**
Appendix T for	**Bechtel Engineering, Procurement and Construction Study,** **AGPAProject, May 2000**
Appendix U Terminal	**Photograph of Anderson Bay Site and Valdez Marine**
Appendix V	**Drawing of Anderson Bay LNG Liquification and Marine Terminal Site [Confidential]**
Appendix W	**TAGS Draft Environmental Impact Statement, Sept. 1987**
Appendix X	**Environmental Impact Statement, Supplemental Submission to U. S. Bureau of Land Management**
Appendix Y	**Yukon Pacific LNG Project, Final Environmental Impact Statement, March 1995 (bound copy)**
Appendix Z	**Trans-Alaska Gas System (TAGS) 42 inch Right-of-Way Modifications, Submissions to Joint Pipeline Coordinator's Office (JPO), October 15, 1992**
Appendix AA	**Valdez Coastal Management Program, Resource Maps, December 1984**
Appendix BB to	**Application to U. S. Department of Energy for Authorization** **Export Liquefied Natural Gas**
Appendix CC	**Route map for proposed 36" OD. Pipeline [Confidential]**
Appendix DD	**Compressor Station A map, over-size drawing. [Confidential]**
Appendix EE	**Compressor Stations for proposed 36" O.D. pipeline [Confidential]**
Appendix FF	**Yukon River Bridge plans/drawings [Confidential]**
Appendix GG	**LNG Terminal Design/Plan Drawing – 1 page sample [Confidential]**

Appendix HH	**FERC letter granting extension of time to commence construction of Anderson Bay LNG export facilities, May 18, 2007**
Appendix II	**Drawing/Plans showing bore hole locations for Anderson Bay LNG Terminal (over-size drawing)[Confidential]**
Appendix JJ with	**Anderson Bay LNG Plant and Terminal Site, Grid Layout**
	preliminary borehole and trench locations (over-size drawing) [Confidential]
Appendix KK	**Pipeline drawing showing pipeline location at elevation along Atigun River and Atigun Camp. [Confidential]**
Appendix LL	**AOGCC Report re Rule 9, July 10, 2007**
Appendix MM	**Project Labor Agreement**
Appendix NN	**AGPA Financial Model (Excel Spreadsheet)**

1. Executive Summary

1.1 The Alaska Gasline Port Authority

The Alaska Gasline Port Authority (the "**Port Authority**") is a municipal port authority established on October 5, 1999, in accordance with the Alaska Municipal Port Authority Act, AS 29.35.600 et seq., which allows for the creation of municipal port authorities to "provide for the development of a port or ports for transportation related commerce within the territory of the authority."

The Port Authority was formed by the municipalities of the North Slope Borough, Fairbanks North Star Borough and the City of Valdez to develop, build or cause to be built, finance, and operate or cause to be operated a project to monetize Alaska's North Slope natural gas, which would include a trans-Alaska gas pipeline, liquefaction and gas processing facilities and related infrastructure for the transportation of North Slope natural gas to market (the "**Project**" or the "**All-Alaska Gasline**").

The Port Authority is submitting this application (the "**Application**") to the Alaska Department of Revenue for the issuance of a license pursuant to the Alaska Gasline Inducement Act, AS 43.90.010 et seq. ("**AGIA**"). The Application has been prepared in response to the Request for Applications (the "**RFA**") issued by the State of Alaska (the "**State**") on July 2, 2007, as subsequently amended. The Port Authority hereby requests the award of a license pursuant to AGIA (the "**License**"), enabling the Port Authority and its Project to benefit from the project inducements enumerated in AS 43.90.110. The Port Authority also waives the right to appeal the rejection of this Application as incomplete, the issuance of a License to another applicant, or the determination under AS 43.90.180(b) that no application merits the issuance of a License.

1.2 The Project

LNG Premium

The value of Alaska Natural Gas is maximized by allowing it to enter the global market in the form of LNG.

Historically, the Asian markets have received their natural gas supplies in the form of LNG. The contracts have been long-term and tied to oil prices with floors and ceilings. Many of those contracts are coming to an end and must be renewed. The new contracts that are being negotiated will be tied to oil parity without floors and ceilings. Over time, the price for LNG in Asia will approach oil parity.

Because oil prices have risen sharply recently, the contract price ceilings have caused gas prices to fall sharply in relation to oil. As some of these long-term contracts end, and are replaced with new contracts without price ceilings, the Japanese gas prices are expected to increase in relation to oil and ultimately approach parity.

According to the Institute of Energy Economics, Japan forecast, Asia is offering a premium on average of almost $3.00 per million British thermal units ("**mmBtu**"), compared with the NYMEX future U.S. gas prices under current oil prices.

Allowing Alaskan gas to flow to the Pacific Basin should guarantee Alaska and the producers in Alaska much greater net back values and the flexibility to move to multiple markets and capture premiums related to the weather and other natural market discontinuities.

LNG is the only way that Alaska can participate in the global gas commodity market of the future.

Project Components

The Port Authority's Project consists of the components described below.

1.2.1 Pipeline

The Project will include an 806-mile overland natural gas pipeline extending from Prudhoe Bay to tidewater at Valdez (the "**Pipeline**"), which will run parallel to the existing Trans-Alaska Pipeline System ("**TAPS**"). This will be a dense-phase, 48-inch pipeline, designed to transport Alaska North Slope ("**ANS**") natural gas, which contains a relatively high amount of natural gas liquids ("**NGLs**"). The proposed initial capacity of the Pipeline is approximately 2 billion cubic feet per day ("**bcf/d**") of natural gas at the Pipeline inlet in Prudhoe Bay. The Pipeline will be capable of rapid capacity expansion up to 5.9 bcf/d through the addition of compression facilities.

The Pipeline will transport ANS natural gas to (i) Valdez for liquids extraction and liquefaction prior to shipping to export markets and (ii) in-State delivery points for meeting local Alaska consumer and commercial needs. The Port Authority anticipates that a delivery point at Glennallen would provide natural gas for a spur line to Palmer that would tie into the South Central gas grid as proposed by the Alaska Natural Gas Development Authority ("**ANGDA**").

The Pipeline will be designed to allow a future tie-in at Delta Junction (550 miles south of Prudhoe Bay) for a later spur line from Delta Junction to the Alaska/Canadian border, following the Alcan Highway. Although the Port Authority is not actively pursuing the development of such a project at this time, it is committed to working cooperatively with the sponsor(s) of such a project to maximize the options for monetizing ANS natural gas.

1.2.2 Liquefaction and Liquids Extraction Facilities

The Project will include an integrated liquefaction and fractionation facility in Valdez which will: (a) extract the propane and butane (liquid petroleum gases or "**LPGs**"), from the gas transported through the Pipeline; and (b) produce liquefied natural gas ("**LNG**") using two process trains, each with nominal design capacity of approximately five million metric tons per annum ("**mmta**"), for a total LNG production capacity of ten mmta. The LNG will be exported to markets in Japan, South Korea and Taiwan. Also included are storage and vessel loading facilities for LNG and LPGs (together with the liquefaction and fractionation facilities, the "**LNG Facilities**").

1.2.3 Gas Conditioning Plant

A gas conditioning plant ("**GCP**") will be built at Prudhoe Bay to remove carbon dioxide, water, and trace amounts of hydrogen sulfide from the natural gas feed and to compress and chill the gas to pipeline specifications. The GCP will also be capable of extracting heavier (pentanes+) NGLs, which will be blended into the TAPS stream.

1.3 Substantial Permitting Progress for All Alaska Gas Line

Over eleven years, Yukon Pacific Corporation ("**YPC**") obtained required permits for the All Alaska Gas Line. In 2005, the Port Authority acquired an option to purchase the YPC and its associated permits and rights-of-way for a gas pipeline from the North Slope to Valdez and for an LNG plant in Valdez. While YPC's data, rights-of-way and permits will need to be updated, Bechtel has estimated that their acquisition will save a significant number of years in developing the Project. Consequently, this Project will be able to proceed and monetize Alaskan gas years before an Alaskan Trans-Canadian line.

2. Introduction to the Alaska Gasline Port Authority

2.1 Formation and History

In the United States, there is a long history of creating governmental organizations to promote and develop projects that the private sector is either unwilling or unable to undertake. There are approximately 160 Port Authorities nationwide. They range in size with the largest Port Authority having an operating budget in 2007 of nearly $6 billion. In 1992 legislation was enacted in Alaska, the Alaska Municipal Port Authority Act, AS 29.35.600 et seq., which allows for the creation of municipal port authorities.

To enable municipalities to promote and develop projects that the private sector is either unable or unwilling to undertake, Alaska law allows for the creation of municipal port authorities for the express purpose of "provid[ing] for the development of a port or ports for transportation related commerce within the territory of the authority." AS 29.35.729(5) broadly defines "port" as a "facility of transportation related commerce located within the state."

In 1999, in an effort to overcome perceived economic hurdles associated with an ANS natural gas pipeline project, the voters of the City of Valdez, the Fairbanks North Star Borough and the North Slope Borough decided, by a collective approval of approximately 80 percent, to create the Alaska Gasline Port Authority, with the directive to "build or cause to be built a natural gas pipeline from facilities in the Prudhoe Bay area on the North Slope of Alaska … to Valdez, to make gas available to Alaska consumers and to share the net revenues statewide from the Project." Immediately following the vote, the municipalities responded to the mandate and passed parallel ordinances establishing the Port Authority. The ballot language and election results are attached as **Error! Reference source not found.** to this Application.

2.2 Objectives of the Alaska Gasline Port Authority

Guided by the mandates of the Statehood Compact, the Alaska State Constitution, and Alaska Statutes, the Port Authority has developed the All-Alaska Gasline Project not only to fulfill the goals and requirements of AGIA, but to provide maximum benefits to Alaska.

Perhaps the most important characteristic of the Project's structure is that, as a public entity, the Port Authority is not driven by the need to maximize its profits, but to provide "maximum benefit" to the people of the State of Alaska. In contrast to entities with natural gas development projects elsewhere in the world that compete internally for corporate investment funds, the Port Authority was formed to advance a single project that is completely within Alaska.

Since its inception, the Port Authority has worked to apply the unique structure of a public/private participation to a natural gas pipeline project with the aim of significantly improving the economic viability and, thus, the likelihood of success of bringing ANS natural gas to market. This structure enables the Port Authority to have a singular focus on its mission to:

- enable the development of ANS gas to the maximum benefit of all Alaskans, including the distribution of net project revenues;
- promote Alaska hire throughout construction and operation;
- provide access to gas for existing and additional in state petrochemical industries;
- provide for maximum distribution of Alaska's natural gas throughout the State;
- bring ANS natural gas to markets at long-term competitive prices; and
- bring the benefits of a tax-exempt structure to an ANS gas pipeline project.

Throughout the development of the Project, the Port Authority has enlisted the participation of world leaders in the development of large-scale oil and gas projects for expert advice in the areas of: engineering and design, cost estimation, economic modeling, LNG shipping, and LNG and NGL marketing.

As an Alaskan entity, the Port Authority has designed the Project with the intent of maximizing the benefits to the State of Alaska, while providing attractive returns to the ANS gas producers. The Project offers the following key benefits to Alaskans.

- The Port Authority's goal is to provide maximum availability of reasonably priced pipeline transportation of ANS natural gas and NGLs for Alaskan needs. To that end, the Port Authority is committed to working with the State, should it choose to make available State royalty gas to Alaskans at a price not tied to a Lower 48 gas hub price.
- A non-producer owned pipeline will provide for maximum competition in the development of ANS gas. As a non-producer, publicly-owned entity engaged in natural gas transportation, the Port Authority is not driven to maximize its profits through the pipeline transportation tariff, and will therefore create the most competitive opportunity for additional exploration and development of ANS gas.
- The Port Authority's proposal ensures the earliest development of a transportation project for monetizing ANS gas. The Port Authority has obtained the exclusive rights to utilize existing State and Federal permits and authorizations supporting the Project and is committed to moving forward with project development immediately. The Port Authority has no interest in other project development efforts worldwide and, therefore, is not conflicted over where it will invest money and efforts.
- The Project enjoys strong economics.
- The Project would provide for the highest net present value ("**NPV**") of cash flows to the State of Alaska because (a) it provides ANS producers with access to premium gas markets resulting in strong netback prices; and (b) development can commence sooner than competing proposals.
- All of the Project's pre-construction, construction, start-up, operation, maintenance and value-added jobs will be located within Alaska.
- Because of its proposed initial size of 2 bcf/d, the Project has the highest probability of a successful open season because: (i) the proposed initial volume is within the current gas offtake allowance by the Alaska Oil and Gas Conservation Commission ("**AOGCC**") for the Prudhoe Bay Unit ("**PBU**"); and (ii) the Project is economically

viable at such lower initial volumes and, therefore, does not require the discovery of additional ANS proven gas reserves prior to the initial open season that would be required to support a larger capacity pipeline .

- The implementation of non-producer owned Pipeline that is capable of rapid expansion will provide a strong incentive for ANS explorers to discover, develop and market new gas reserves.

2.3 Over Thirty Years of Public Support for the All-Alaska Gasline Project

The All-Alaska Gasline has consistently been the preferred project of Alaskans statewide. The overwhelmingly supportive votes that created the Port Authority in 1999 and ANGDA in 2002 (ballot language specifically referring to a gas pipeline from the North Slope to Valdez) are only two examples of Alaskans' strong preference for the All-Alaska Gasline.

Dating back as far as the mid 1970's, Alaskans have made it clear that they prefer an All-Alaska Gasline route over a trans-Canadian route:

> Questionnaire Result:
>
> "Dear Fellow Alaskans:
>
> I want to thank all of you who responded to the questionnaire which appeared in the December, 1975, issue of the newsletter.
>
> I received approximately 45,000 responses as of the first of February. The following are the results which are tabulated from the responses received.
>
> Do you support a trans-Alaska gas pipeline as opposed to a trans-Canadian line?
>
> Yes – 85% / No – 8% / Undecided – 9%"
>
> -Senator Ted Stevens
> Newsletter
> December, 1975

There have been numerous resolutions passed by individual communities and the Alaska Municipal League ("**AML**") in support of the Port Authority's All Alaska Gasline project. Such community and AML resolutions are attached in **Error! Reference source not found.** & E.

In May 2005, when then Governor Frank Murkowski was negotiating exclusively for a producer-owned gas pipeline project through Canada, two public opinion polls were conducted that focused on what Alaskans understood and felt about issues surrounding the development of a ANS natural gas transportation project. Dave Dittman of Dittman Research Corp. conducted an "Alaska Poll" that asked Alaskans the following question:

> "At the present time, there appear to be three different proposals to bring Alaska's North Slope natural gas to market. A company named TransCanada, which says it already has all the Canadian permits needed to build a pipeline from the North Slope through Canada to the Mid-Western United States. A combined proposal by ConocoPhillips, BP and Exxon – who have leased the rights to Alaska's North Slope gas – they would also build a

> pipeline from the North Slope through Canada to the Mid-Western United States. And a proposal by the Alaska Gasline Port Authority to build a pipeline from the North Slope to Valdez, where the gas would be liquefied and transported to market by tankers.
>
> Just based on that information, which proposal do you think the state should select?"

The results of the poll indicated that the majority of Alaskans from every regional, political, age and gender demographic believed the State should select the proposal of the Port Authority for an All Alaska Gasline. The poll results are attached in **Error! Reference source not found.**.

Around that same time, the Port Authority hired Jean Craciun of CRG Research to poll Alaskans about their understanding of the ownership issues surrounding Alaska's natural gas and their preferences on how it should be developed. The results of that poll showed that 77 percent of the persons polled understood that it is the State that owns the gas resources and 62 percent favored the All Alaska Gasline as the project that they "would most like to see happen". The poll results are attached in **Error! Reference source not found.**.

As recently as November 25, 2007, former Governor Walter Hickel provided an unsolicited endorsement of the All-Alaska Gasline and the Port Authority's Application:

> "I am rooting for the Alaska Gasline Port Authority, a consortium of three communities located along the oil pipeline route. I am not privy to their plans or their proposal, but their leadership is outstanding, and they want to build an All-Alaska LNG system, the concept I believe in."
>
> "I support an all-Alaska gas line from Prudhoe Bay to Valdez for the following reasons: a much sooner start up time, more revenue for the state and municipalities, guaranteed access to the gas by Alaskans, value-added jobs that will last generations and flexible markets for our LNG."
>
> Governor Walter Hickel
> "We Alaskans can build our own gas line"
> Comment, Anchorage Daily News
> November 25, 2007

3. Project Description

3.1 Introduction

This section of the Application describes each Project component, as required in RFA section 2.1, and is organized as follows:

- Section 3.2 provides a description and plan for the Pipeline component of the Project;
- Section 3.3 provides a description of the GCP;
- Section 3.4 provides a description of the LNG Facilities in Valdez;
- Section 3.5 provides a description of the marine transportation element of the Project, including tanker transportation of LNG and NGLs from Valdez to destination markets; and
- Section 3.6 provides a description of the NGL processing and marketing elements of the Project.

Figure 1 below shows a map of Project facilities in Alaska, including the GCP, Pipeline and LNG Facilities.

Figure 1 Project Facilities Map

3.2 Pipeline

3.2.1 Route

The Pipeline route begins at Prudhoe Bay and runs south to Valdez parallel and adjacent to TAPS in the gas pipeline corridor identified in the Federal Right-of-Way Grant issued to the Yukon Pacific Corporation ("**YPC**") on October 17, 1988 and in the State of Alaska Conditional Right of Way Lease issued to YPC on December 10, 1988.

Pipeline Alignment Sheets, dated June 20, 2003, which show the Pipeline alignment within the existing permitted gas pipeline corridor, are provided in **Error! Reference source not found.**.

3.2.2 Technical Parameters

Preliminary engineering work for the Pipeline was performed by the Bechtel Corporation ("**Bechtel**") in 2000 under an Engineering, Procurement and Construction Study (the "**EPC Study**") prepared by Bechtel for the Project, which is attached herein as **Error! Reference source not found.**.

The engineering data has been subsequently updated by Bechtel. For a discussion of access to the updated detailed technical data related to the Port Authority's Application, please refer to Section 7.2.

3.2.3 Receipt and Delivery Points, Major Markets Served

The Pipeline will deliver ANS natural gas to Valdez for liquefaction and liquids extraction at the LNG Facilities. The Pipeline will also deliver ANS gas to delivery points along its route to serve in-State demand for natural gas. See Section 4.3.9 below for a detailed discussion of in-State delivery points.

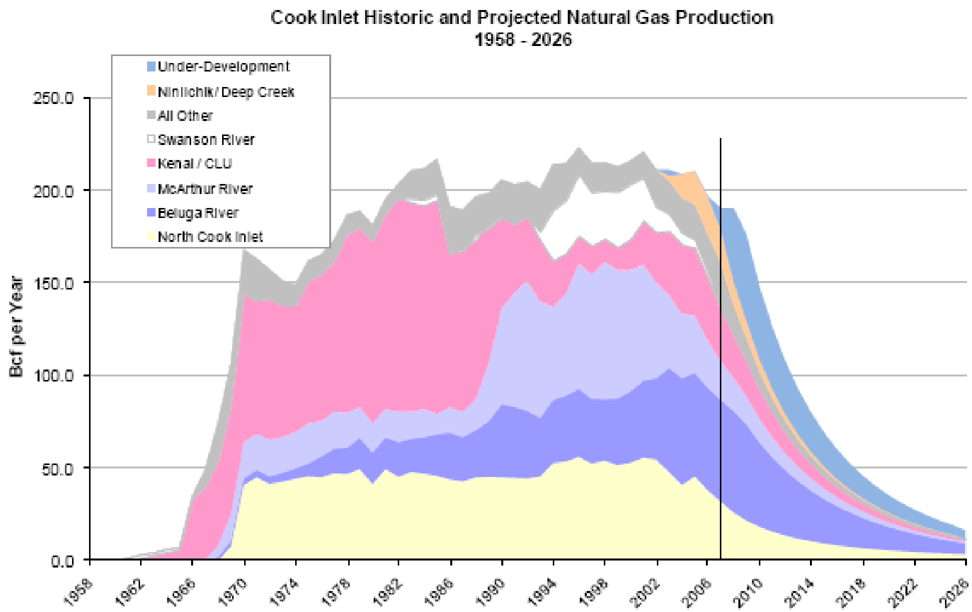
Importance of Gas Supply to South Central Alaska

Gas production in the Cook Inlet is forecasted to fall sharply over the next few years. In June of 2004, a U.S. Department of Energy ("**DOE**") study projected a 75% drop in production from over 200 bcf per year in 2005 to less than 50 bcf per year by 2014.[1] The Alaska Department of Natural Resources ("**DNR**") most recent annual report was slightly more optimistic, estimating Cook Inlet gas production to reach 52.7 bcf per year in 2017.[2]

[1] Presentation of Tony Izzo, President/CEO of ENSTAR Natural Gas Company, Energy Supply in South Central Alaska (2006).

[2] State of Alaska Department of Natural Resources, 2007 Annual Report, p. 3-25 (July 2007).

Figure 2 Cook Inlet Historic and Project Natural Gas Consumption



Source: DNR, 2007 Annual Report

The impact of this reduction will be dramatic. As supply constricts, medium-term South Central Alaska gas prices will rise significantly, meaning Alaskan consumers can expect increased gas and power utility rates. Reductions in base supply have already begun to directly affect industrial users.

Agrium, which consumes natural gas for the production of urea, was the first industry to suffer from such reductions. Agrium shut down its Nikiski plant in the winter of 2006-2007 so gas could be made available for higher priority home heating. In September of this year, Agrium closed its Kenai fertilizer facility, laying off more than 100 employees. The Tesoro petroleum refinery at Nikiski which began operations in 1969, processes oil produced from Cook Inlet. It normally uses natural gas for fuel, and as feedstock for its hydrocracker unit. In late 2006, due to a gas shortage estimated at 42% below the plant's required volumes, it was forced to use its own high-value products, such as butane, propane and ultra-low-sulfur diesel, to fuel the refinery. It is expected that the Marathon/ConocoPhillips liquefaction facilities in Nikiski, which have been shipping LNG to Japan since 1969, will also cease operation in the next few years.

DOE predicts that around 2011, not only will there not be enough gas for heavy industrial use, but Cook Inlet gas production will no longer be able to supply electric power generation demand.[3] Beyond 2015, consumer gas utility demand is expected to outstrip local supply.[4]

[3] Id. at 11.

[4] Id.

The consequences of not securing the supply of ANS natural gas to the South Central region by 2015 could be severe. The curtailment of industrial consumption of natural gas in Nikiski for the production of urea, refining, and LNG export would result in significant job losses in the Kenai area. Further, power generation along the Railbelt will have to use more expensive fuel substitutes, which could mean not only significant increases in electricity generation costs but could also incur high switchover costs. Alaska, which has the largest undeveloped natural gas reserves in the United States, could become an importer of LNG.

Receipt Points

The principal receipt point for natural gas transported on the Pipeline will be Prudhoe Bay, at the outlet of the GCP. The Port Authority anticipates the discovery and development of new natural gas reserves in locations in Alaska outside of Prudhoe Bay, such as, for example, the Foothills area. Monetizing such natural gas reserves could necessitate the provision of additional receipt points along the Pipeline route that enable shippers to market such gas without the need to first transport it to Prudhoe Bay.

To the extent that gas producers and prospective shippers in areas such as the Foothills, or other areas, are ready to make gas available for commitment in the initial binding open season, the Port Authority will work with such producers and prospective shippers with the aim of modifying the Pipeline design to achieve a rational and cost-effective distribution of receipt points and accommodate the need of such shippers to have access to the Pipeline.

To the extent the need for such additional receipts points arises after the initial open season, the Port Authority will accept and evaluate requests for such receipt points during the periodic market assessments for expansion mandated by AGIA.

3.3 Gas Conditioning Plant

The Port Authority is in discussions with a Regional native Corporation regarding the building, owning and operation of the GCP. Based on industry experience, familiarity with Alaska and their financial successes over the past many years, the Port Authority believe it is the appropriate entity to perform this function. The Port Authority and Regional Corporation are currently in discussions regarding this component of the Project.

It is anticipated that the GCP will be owned and operated by a venture consisting of Regional Corporation and possibly one or more additional companies with significant experience in the gas processing sector (the "**GCP Participants**"). As such, the GCP would provide gas processing services to the Project on a third-party basis. In order to achieve the most attractive commercial terms for the GCP, the Port Authority has deferred the selection of the GCP Participants and negotiation of definitive participation arrangements until after award of the License. A detailed description of the anticipated commercial structure for the GCP is provided in Section 4.4 below.

The capacity of the GCP will be sized to accommodate the gas processing needs of the anticipated Pipeline capacity, which will include the gas supply requirements of the LNG Facility and anticipated demand for natural gas from in-State consumers.

Preliminary engineering work for the GCP was performed by Bechtel under the EPC Study, which is attached herein as **Error! Reference source not found.**. The engineering data has been subsequently updated by Bechtel. For a discussion of access to updated detailed technical data related to the Port Authority's Application, please refer to Section 7.2. It will also include design components that will permit the expansion of gas shipments to accommodate a Valdez LNG terminal expansion.

3.4 LNG Facilities in Valdez

The LNG Facilities will be located at Anderson Bay in the area of Valdez, pursuant to the authorization granted by the Federal Energy Regulatory Commission ("**FERC**") for such a facility, which is discussed in Section 4.9.1 below.

The planned LNG production capacity is 10 mmta. The LNG Facilities will include two liquefaction process trains with capacity of 5 mmta each. LPG production at the fractionation plant that will be included in the LNG Facilities will depend on the actual gas composition of the feed gas. Based on the indicative gas composition assumptions provided in the RFA, it is expected to be approximately 19.2 thousand barrels per day ("**mbpd**"). Inlet gas volume will be determined by (i) the volume requirements to meet the design LNG production capacity, (ii) gas volumes attributable to extracted LPGs, and (iii) fuel consumption and losses at the LNG Facilities, and is currently estimated to be approximately 1.6 bcf/d.

Preliminary engineering work for the LNG Facilities was performed by Bechtel under the EPC Study, which is attached herein as **Error! Reference source not found.**. The engineering data has been subsequently updated by Bechtel. For a discussion of access to detailed technical data related to the LNG Facilities proposed in the Application, including information related to storage tanks and marine terminal facilities, please refer to Section 7.2 and **Error! Reference source not found.**.

The anticipated commercial structure for the LNG Facilities is described in Section 4.5 below.

3.5 Marine Transportation for LNG and NGL

3.5.1 LNG Tanker Transportation

The Project will not own LNG tankers. LNG marine transportation services will be obtained from third parties, under long term time charter arrangements typical in the LNG industry. The providers of marine transportation services will be selected under a competitive tender process.

The Port Authority has developed a relationship with Mitsui O.S.K Lines, Ltd. ("**MOL**") and its subsidiaries BGT Limited and BLNG Inc (together with MOL, the "**MOL Companies**"). MOL is a global leader in marine transportation and has the largest tanker fleet in the world, including crude carriers, product carriers, LNG carriers, LPG carriers and methanol carriers. MOL is a leader in LNG transportation for LNG projects worldwide. MOL and its group of companies own and/or participate in 80 LNG vessels (including 21 vessels under construction), which represents approximately a quarter of the world's existing (or under construction) LNG vessels. A detailed description of MOL's LNG fleet is provided and its experience in LNG projects is provided in **Error! Reference source not found.**.

Pursuant to a Teaming Agreement between the Port Authority and the MOL Companies (attached as **Error! Reference source not found.**), the Port Authority and the MOL Companies have agreed to work together to develop the marine transportation elements of the Project, including the development of a plan for procurement and implementation of LNG transportation services in structure that is most suitable to the Project.

Pursuant to the Teaming Agreement with the Port Authority, the MOL Companies have provided a cost estimate for marine transportation services based on several options for new-building LNG vessels. The data in the cost estimate provided to the Port Authority contains proprietary information that is confidential, and such information has been excluded from the public portion of this Application. The confidential cost estimate data is attached separately in **Error! Reference source not found.**.

The Port Authority has separately received an additional cost estimate from a major Japanese conglomerate, whose business activities include the trading and marketing of LNG and the provision of LNG tanker services. This company has provided to the Port Authority an additional confidential cost estimate for LNG marine transportation for the Project.

The number of LNG tankers required to transport the LNG volumes is primarily a function of: (a) tanker size; and (b) distance to the destination market. The precise fleet configuration for the Project will be determined once the actual sales volumes of LNG to each market in Japan, Korea and/or Taiwan has been finalized, and binding bids under a competitive tender for the provision of marine transportation services have been obtained by the Project. At this time, it is anticipated that the LNG tankers for the Project could range between 147,000 cubic meters ("**m^3**") and 177,000 m^3 class. Vessels in this size range are optimal for the Project in terms of cost and access to East Asian receiving terminals.

Depending on the allocation of offtake LNG volume and the size of vessels selected by the Project, it is anticipated that between 8 and 12 newbuilding vessels would be required to transport the volume of LNG produced. Detailed description and technical characteristics of the different classes of vessels which are currently being evaluated as options for the Project are provided in **Error! Reference source not found.**.

A description of the process of procuring LNG marine transportation services for the Project and the anticipated commercial arrangements for the LNG tanker component of the Project is provided in Section 4.6.

3.5.2 LPG Tanker Transportation

LPG marine transportation services will similarly be obtained from third parties pursuant to a competitive tender process. LPG tankers are available for chartering on a short term basis, e.g., one year, or on longer term basis of ten or more years.

Pursuant to the Teaming Agreement between the Port Authority and the MOL Companies, the Port Authority and the MOL Companies have agreed to also work together to develop the LPG tanker transportation framework for the Project. MOL has 45 years of experience in the LPG tanker business and was the first owner of a fully refrigerated LPG carrier in the world. MOL's is an owner and operator of five very large gas carriers ("**VLGCs**"), or LPG tankers with a capacity in excess of 70,000 m^3.), one mid-size ammonia carrier and one pressurized LPG carrier. MOL is the operator of an additional three VLGCs and has a further ten LPG and ammonia carriers under its management. A description of MOL's LPG fleet and expertise in LPG tanker services is provided in **Error! Reference source not found.**.

3.6 Gas Processing and NGL Markets

Two separate components of the Project will perform functions related to gas processing and marketing of NGLs: (a) the GCP at Prudhoe Bay; and (b) the integrated liquefaction and fractionation LNG Facilities in Valdez.

The GCP will perform gas processing functions to remove carbon dioxide, water, hydrogen sulfide and other impurities from the natural gas feed and to compress and chill the gas to the Pipeline's specifications. The GCP will extract heavier NGLs (pentanes+), which will be blended into the TAPS stream. For a detailed discussion of the technical and commercial aspects of the GCP, please refer to Sections 3.3 and 4.4.

The lighter NGL fractions, ethane, propane and butane, which cannot be safely blended into the TAPS stream and will not be extracted at the GCP, will be transported through the Pipeline to Valdez for processing at the LNG Facilities. At this time, the Port Authority does not anticipate the near term development of an ethane-consuming petrochemical industry in South-central Alaska and, therefore, no assumption has been made for ethane extraction and marketing in the initial Project design. The Port Authority, however, is committed to providing maximum opportunity for Alaska to benefit from the monetization of ANS natural gas by making available gas and NGLs to local consumers and industries and thus spurring the growth of new industries, including ethane-based petrochemical facilities or other similar consumers of NGLs in the State. The Port Authority will periodically assess the market interest in adding ethane-extraction capability to the Project to serve the development of such new industries.

Until such ethane processing capability is developed in the future, the ethane fraction in the ANS gas will be included in the LNG produced at the LNG Facilities. It should be noted that East Asian LNG buyers are accustomed to receiving LNG with a high heating value and that, as discussed in Section 12.1 below, the forecast prices for LNG in the targeted markets are highly attractive and, therefore, the ethane fraction in the natural gas stream will obtain high sales value.

Alternatively, in the event that a Canadian pipeline is developed in the future to transport ANS gas to markets in Canada and the U.S., the Port Authority is committed to working with the sponsor(s) of such project and with shippers of natural gas to determine the optimal location of gas processing and NGL extraction facilities that would provide the highest value for Alaskan NGLs by maximizing their marketing options. In one such scenario, it is anticipated that a gas processing and NGL extraction facility could be located at Delta Junction to enable the redirection of NGLs to the best market available at each point in time via either (a) the Valdez terminal for sea-borne shipping worldwide, or (b) the Canadian pipeline to markets in Canada or the U.S. Midwest.

Anticipated commercial arrangements for the LPG extraction and marketing functions are described in Section 4.8 below. For a description of the targeted markets for propane and butane, please refer to Section 12.1.5.

4. Development Plan

4.1 Front End Engineering Design Plan

The Port Authority plans to obtain services for the preparation of the front end engineering design ("**FEED**") package pursuant to a competitive tender process with qualified engineering firms. It is expected that requests for proposals for the FEED package will be issued shortly after the conclusion of the initial open season, or approximately 18 months prior to the target date for issuance of the notice to proceed ("**NTP**") under the Project's engineering, procurement and construction ("**EPC**") contracts. It is expected that the FEED package will be awarded approximately 14 months prior to the target NTP date.

For a discussion of access to updated detailed technical data related to the Port Authority's Application, please refer to Section 7.2.

4.2 Stakeholder Issues Management Plan

4.2.1 Introduction

The Project, which will involve the construction of an 806-mile pipeline that traverses the length of Alaska, together with the construction of gas conditioning facilities at Prudhoe Bay and gas liquefaction and processing facilities in Valdez will be the biggest construction project in the United States. Careful planning and coordination with all stakeholders will be of utmost importance during the Project development phase to ensure that (a) the benefits associated with the Project are maximized; and (b) the negative impact of construction activities are minimized.

A key objective of the Project stakeholder issues management plan ("**SIMP**") is to establish effective means of communication in order to ensure the stakeholders are well informed about Project activities and that the Project team is conversant with, and can respond to, manage or mitigate stakeholder concerns.

The key stakeholders in the Project include:

- U.S. military landowners along the Pipeline right-of-way, including the U.S. Department of Defense, U.S. Air Force and U.S. Army
- the U.S. Park Service
- individual Alaskan landholders, as well as Alaska Native Corporations
- Political subdivisions of the state, such as the North Slope Borough, the Fairbanks North Star Borough, the City of North Pole, the City of Valdez, Delta Junction, Glennallen, Anchorage, and other communities
- the U.S. federal government
- Alaska emergency service providers

- Alaska State Troopers
- labor organizations
- recreational land users
- non governmental organizations (NGOs)
- oil industry
- the University of Alaska
- education/training providers
- resource developers, contractors, and material and equipment providers
- the general public
- utilities

Landowners in the Pipeline right-of-way include:

- Ahtna, Inc. (Native Corporation)
- U.S. Department of Interior, Bureau of Land Management
- Black Rapids Training Site
- Chena River Lake Flood Control Project
- Eielson Air Force Base
- Fairbanks North Star Borough
- Golden Valley Electric Association
- Mental Health Land Trust
- Municipality of Valdez
- Private Land Owners
- Private – Alaska Native Allotment
- Private Mining Claim
- Private Subdivision
- State of Alaska
- State Subdivision
- U.S. Army Corps of Engineers
- U.S. Forest Service

Upon award of the AGIA License, the Port Authority will appoint a SIMP manager to begin a coordinated implementation of the SIMP by:

(1) Establishing, within the Port Authority's internet website, a Project overview citing specific timelines for the Project. In addition, the website will request that stakeholders forward their concerns or questions to the SIMP team for evaluation and/or response. The website will enable stakeholders to provide input on a

continuous basis. This approach will be similar to a web-question/answer approach used with RFA inquiries under the AGIA application process.

(2) Compiling a list of individual representatives of all the major stakeholders within the first 30 days after License award. The goal will be to ensure that all major stakeholders have a representative to act as a liaison with the Port Authority. Communication, at a minimum, with such representatives will be through a regular email update addressing major developments with the Project.

(3) Establishing within 60 days of License award, an advertising and marketing campaign designed to inform all identified stakeholders and the public about the Project. The campaign will be conducted via print, broadcast, and electronic media, as well by targeted direct mail. The advertising campaign will cover local, regional, national and international audiences.

(4) Scheduling and conducting public presentations and hearings in municipalities and other areas of population that would be affected by the Project, such as: Barrow, Coldfoot/Wiseman, Fairbanks, Eielson Air Force Base, Delta, Fort Greely, Paxson, Glennallen, and Valdez, and Anchorage. Other communities and villages will be identified via the public input/outreach process.

(5) Responding to input received from the public hearings within 30 days of the close of the proposed public comment period.

(6) Holding a second round of public hearings, three to six months later, with a special emphasis on presenting how the Port Authority has addressed the received public comments and concerns and to accept additional input.

(7) Incorporating additional relevant and beneficial input received into Port Authority planning.

4.2.2 Land-Based Interests

A list of land owners along the Project route is provided in **Error! Reference source not found.**.

The communities identified along the Project route consist of the following:

- North Slope Borough, including the villages of:
  - Anaktuvuk Pass
  - Barrow
  - Kaktovik
  - Nuiqsut
- Between the North Slope Borough and Fairbanks North Star Borough:
  - Wiseman
  - Bettles / Evansville

  - Allakaket / Alatna
  - Stevens Village
  - Rampart
  - Minto
  - Livengood
- Between the Fairbanks North Star Borough and Valdez:
  - City of Fairbanks
  - City of North Pole
  - Delta Junction
  - Fort Greeley
  - Glennallen / Copper Center Area
  - Valdez

4.2.3 Recreation, Aesthetics, and Wilderness

Introduction

As with many other aspects of the Project, there would be both positive and negative impacts on recreation, wilderness, and aesthetics. Generally, the negative impacts would emanate from construction noise, dust, and visual scars on otherwise undisturbed and natural areas. New recreation access points would be created by the Project. Greater numbers of people would reside in the State.

Recreational use along roads associated with this route from Livengood south to the Valdez area is heavy and would be impacted primarily during construction by competing uses between tourist and construction workers, since most popular recreation facilities are highway oriented.

Recreation

The area from Chandalar Shelf north to Prudhoe Bay at present has only light recreation use, consisting mainly of fly-in hunting and fishing. Several hunting guides operate from airstrips near TAPS, especially the Galbraith Lake and Sagwon airstrips. Recreational use along the Dalton Highway would also increase due to the number of construction workers. Impacts on recreation would be expected to be moderate.

The proposed Pipeline route runs parallel to, or a few miles from, a highway system along its entire route. Lateral access roads from the existing highway to the proposed route would, if open to the public, very likely be used by recreationists. This access would extend the area and amount of use that already exists and could significantly increase the recreational opportunities.

Examples of potential openings of new access to presently roadless areas would include: the west side of Atigun River above Galbraith Lake, Summit Lake and Grayling Lake. Impacts would be moderate on these areas. The Galbraith Lake and the Sukakpak Mountain areas are well-known entrance points to the nearly Brooks Range federal conservation units, including Gates of the Arctic and the nearby Arctic National Wildlife Refuge.

During construction there would be moderate recreational use of areas along the pipeline by construction workers. Recreation opportunities for travelers and vacationers on highways along the route would be temporarily altered during the construction period. However, there would be moderate, increased use by construction workers and others in the winter months where roads are kept open and maintained, resulting in minor impacts to recreation.

Unless steps are taken to provide adequate recreation facilities, campgrounds, picnic areas, overlooks, boat access sites, trail leads, parking areas, turnouts, and rest stops, damage to the vegetation and trash from uncontrolled recreation use and a general degradation of recreation and aesthetics would result. Additionally, due to the typical influx of tourists to Alaska and the presence of the construction workers and their families, the increased use of public campgrounds could cause an increased potential for human/carnivore interaction due to feeding by the visitors and poor handling of garbage and other attractants. An example of a closing of a public campground occurred during the construction of TAPS when the campground on the Upper, Little Tonsina, near Pump Station Number 12 where marauding bears became habituated to humans.

Odors from engine exhaust, fuel areas, and camps would be evident near recreational areas during construction.

Wildlife populations near the corridor would be temporarily affected by the construction of the proposed project and possibly by increased pressure from hunting and harassment by workers.

Unregulated use by all-terrain vehicles, trail bikes, snowmobiles, and other off-road vehicles could have a significant adverse impact on recreation and aesthetics by permanently scarring the landscape, damaging the vegetation, compacting the soil, causing erosion, and harassing the wildlife. These activities would probably continue to be restricted by the State as they presently are along the Dalton Highway. Therefore, the impacts would be minor.

Project-related recreational needs would increase potential for recreational use of the area because more people would become aware of such opportunities through publicity and personal association with employees. More use would inevitably bring more control; thus, present recreationists might experience such things as reservation systems, reduced options for types of experiences, and restrictions on places they might go and heir length of stay. Additionally, the tourism industry expansion would be curtailed in certain areas during construction, especially at major interest points such as Keystone Canyon and Worthington Glacier.

Aesthetics

Aesthetics is a value judgment; everyone interprets and experiences it differently. Some would view the project's increased availability of a unique area to more people to be a benefit while others would say it is an intrusion.

A more direct impact of construction on recreation resource would be the visual scars resulting from buried pipeline construction and the visual impacts of aerial stream crossings. In all cases this gas pipeline would be at least a third utility and perhaps a fourth to be located in the corridor area; consequently, it would not be the same as building a new pipeline across an undisturbed area.

Facilities such as communications towers, buildings at compressor sites, block valves, and the LNG site, would be visible from the air and highway for great distances in some cases. At times, the linear pipeline berm would also be visible to those hiking in the nearby mountains. Lights on communications towers and at compressor stations would be visible over long distances, especially at night. Impacts would be minor to moderate along the corridor. Co-use of existing facilities such as communications facilities would result in no impact.

Nearly all of the proposed right-of-way south of the Brooks Range would require the clearing of brush and forest cover. This would significantly alter the natural environment and in these areas would degrade existing aesthetic values, particularly where long straight clearings are visible from the road. These impacts would be moderate during construction and minor during operation.

Recreationists within several miles of the line would have their experiences affected by construction and operation activities. When the route passes within a mile or so of presently used recreational areas, the impacts would typically be minor, especially during construction. Noise, traffic, additional dust, and the scars from clearing and ditching would decrease the experience, sometimes to a considerable degree. Impacts in the vicinity of TAPS during construction would be moderate and negligible thereafter.

Many of the aesthetic impacts have already been discussed under recreation. The major impact to many people would be the viewshed as seen during hiking, driving on the main roads, and boating on rivers as well as from the air. For those people whose appreciation of aesthetic quality is related to beauty, sensations, or to the congruity of the environmental features, the proposed project would have a major adverse effect on the resource. Visual impacts in forested areas are particularly severe and long-term in areas of high relief or low vegetation. The pipeline right-of-way, borrow sites, cut and fills, and access roads would remain landscape features indefinitely causing long-term aesthetically adverse impacts. But for others, long tangents might add interest to otherwise repetitive, though natural views.

Wilderness

The preferred pipeline routing involves two small areas where existing wilderness studies and recommendations to Congress have not been completed. YPC has previously identified optional routing at MP 95 and MP 110 that would avoid areas "having wilderness values." These optional routings are specifically incorporated into the Project EIS. There are several federally designated wilderness areas near the route, including the Arctic National Wildlife Refuge, the Gates of the Arctic National Park and Preserve, and the Wrangell-Saint Elias National Park and Preserve, which are primarily roadless and wilderness areas. None of these areas would be directly disturbed by the proposed project. Impacts should be minor. There would be some increased use of wilderness areas in Alaska as a result of construction and operational employment opportunities created by the Project.

Wild Rivers and Chugach National Forest

There would be no direct impacts to the Gulkana and Delta Wild and Scenic River areas since the route would not cross the designated portions of these rivers. Units of national park and refuge systems authorized by ANILCA are not involved. The portion of the LNG terminal buffer area within the Chugach National Forest is classified as a general multiple-use forest area. Secondary impacts to these recreation areas would occur due to construction workers using recreational areas. Also, the buffer area for the LNG terminal that is in the Chugach National Forest has been transferred by the USFS to State ownership under the Alaska Statehood Act.

Valdez Area

Most recreation in the Valdez area is centered around fishing; sightseeing by car, boat, and by foot; and some hunting. These recreational pursuits would be stressed considerably during construction due to the large influx of people to an area with limited accessibility. The aesthetic experience of fishing for anadromous species such as salmon would be impacted, but there are other factors which affect these activities more than crowded stream access points.

Hiking opportunities should be increased after construction, especially in such areas as Keystone Canyon where accessibility to trailheads would be somewhat improved. The locally popular Goat Trail and Bridal Veil Falls would be affected only during the construction period. Aesthetics of this region would be only moderately affected once construction was completed.

Summary

The impacts to recreation and aesthetics would be widespread due to the length of the area disturbed, but the band of disturbance would be quite narrow.

Primary disturbance would occur during construction and would involve impacts to present uses and users of the area, especially by tourists, sightseers, and wilderness enthusiasts. During construction we anticipate the following short-term impacts on tourism:

- increased highway traffic
- increased air passenger activity
- shortage of hotel and other visitor accommodations

- problems hiring and retaining tourism service employees due to the attraction of higher paying pipeline jobs

However, these impacts should be offset by the following:

- The airlines will likely add more flights.
- The year-round occupancy rates should be significantly higher, thus increasing bed tax revenues (where applicable), which are used primarily to support tourism promotion and development efforts.
- Prudhoe Bay, the TAPS pipeline, and Valdez Marine Terminal are major tourist attractions.
- Improvements in the transportation infrastructure will be of long-term benefit to the tourism industry.
- Increased state and local government revenues from the Project can be used to advertise tourism and finance development projects.

Impacts to aesthetics would be more long-lasting. The visual impacts would include long stretches of linear clearing of vegetation and many new borrow sites where vegetation has been removed. Their impacts would be moderate.

There would be negligible impact on wilderness value since the band of increased disturbance is quite narrow and would not change the existing character of a majority of the route.

4.3 Commercial Plan for Pipeline

The Port Authority has begun discussions with Alaska Regional Native Corporations, whose land the pipeline will cross, with the goal of facilitating the formation of a consortium consisting of Native Corporations to work as the operator and maintenance entity of the pipeline. While there may be a role for an out-of-state consortium partner with significant pipeline operation experience, it is the goal of the Port Authority to allow the Regional Native Corporations to have the first opportunity to fill that role. Alaska has matured significantly since TAPS was constructed and operations began. The Port Authority believes the local Regional Corporations should be provided the first opportunity to assemble their own team to perform these functions.

4.3.1 Plan Prior to Open Season

Description of Level of FEED and Amount of Field Work

For a discussion of access to detailed technical data related to the Port Authority's Application, please refer to Section 7.2.

Description of Steps and Strategies to Facilitate a Successful Initial Binding Open Season

The Port Authority has developed the following strategies to facilitate a successful initial binding open season:

- The Port Authority's Project, at 2 bcf/d, is sized such that it can move forward without the identification of additional ANS reserves. To finance larger projects more than the approximately 35 tcf of gas currently available will need to be committed at an initial open season. Thus the Port Authority's Project eliminates the delay and risk associated with mandatory pre-open season exploration.

- The Port Authority's Project is designed to be within the allowed AOGCC Rule 9[5] offtake rate of 2.7 bcf/d for the Prudhoe Bay Unit. The AOGCC has repeatedly stated that gas sales from Prudhoe Bay at rates higher than 2 bcf/d may or may not be allowed if a proposed larger Project requires the agency to revisit Rule 9.[6] The AOGCC has also recently affirmed that gas sales not exceeding 2.0 bcf/d can occur under existing Rule 9 without a hydrocarbon depletion plan, something AOGCC has stated it may require as part of any future amendment to Rule 9.[7] The size of the Port Authority's Project thus further reduces the risk of there being insufficient gas at the time of the initial open season.

- Since the Port Authority's Project can go forward using only Prudhoe Bay gas within the limits of Rule 9 in the early years, the Project will not risk delay by the need to undertake a gas cycling Project in Point Thomson (see Section 15).

- The Project size also eliminates concerns associated with marketing larger volumes of gas. Unlike, for instance, a 4 bcf/d project to Alberta or the U.S. Midwest, participants in an open season need not worry about over supplying regional markets or associated price declines.

- Alaska LNG can expect a long-term price premium over gas marketed via a Canadian Highway line due to (i) Asian LNG prices approaching oil parity and (ii) the flexibility to take cargos to the highest priced market. The Port Authority believes this sustainable premium will substantially aid its open season efforts.

- The Port Authority recognized several years ago that a key piece to the success of any Alaska gas pipeline project was the willingness of Point Thomson working interest owners to develop the field's resources and commit gas to sale. In Section 15 the Port Authority explains that by terminating the former unit and underlying leases, the State is in the position to demand development on its timeline. The Port Authority thus views the Point Thomson's 8 tcf of gas resources as now available to the Project upon receipt of the License.

[5] AOGCC Rule 9 of Conservation Order 341D: "The maximum annual average gas offtake rate is 2.7 billion standard cubic feet per day, which contemplates an annual average gas pipeline delivery sales rate of 2.0 billion standard cubic feet per day of pipeline quality gas when treating and transportation facilities are available."

[6] Report of the Commission Inquiry Into Amending Rule 9 ("Pool Off-Take Rates"), CO 341D, for the Prudhoe Bay Oil Pool, Prudhoe Bay Field, Alaska Oil and Gas Conservation Commission (July 10, 2007) (Attached as Appendix LL).

[7] Id..

Contingency Plans to Obtain Commitments in a Successful Initial Binding Open Season

Like the State, the Port Authority is hopeful that the Prudhoe Bay working interest owners will abide by the terms of their leases and participate in an initial open season. However, like it did for Point Thomson in 2005, the Port Authority has developed a detailed legal strategy for the State to follow should they refuse, or threaten to refuse, to commit gas in the initial open season. The Port Authority is available to go over this confidential strategy with the State upon request.

4.3.2 Plan for Open Season

The Port Authority recognizes that certain Alaskan pipeline projects are subject to the FERC rules that govern their open-season procedures.[8] These procedures apply only to a "natural gas pipeline system that carries Alaska natural gas to the international border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission) that is authorized under the Alaska Natural Gas Transportation Act of 1976 or section 103 of the Alaska Natural Gas Pipeline Act."[9] Because the Project does not meet this definition, FERC's open-season rules do not apply to it.

Nonetheless, the Port Authority plans to hold an open season designed to meet the same objectives that FERC's open season process is designed to meet, namely: (a) facilitating the timely development of an Alaska natural gas transportation project; and (b) encouraging the exploration for new gas reserves by assuring competitive access to the pipeline. The process will seek to secure binding bids for capacity on the Pipeline. The Port Authority is committed to awarding capacity to shippers on a nondiscriminatory basis.

The Port Authority plans to conduct its open season as follows:

- The Port Authority will seek an aggregate volume commitment from shippers sufficient to cover: (a) 100% of the feed gas requirements of the LNG facility in Valdez; and (b) the projected in-State gas consumption needs. The planned Pipeline capacity to cover the above gas supply requirements, after taking into account (i) the gas volume attributable to NGLs extracted from the gas stream and (ii) fuel use in the system is approximately 1.8 bcf/d at the inlet to the Pipeline. To the extent that the projected in-State consumption needs change during the development phase of the Project, the Pipeline design capacity will be re-configured to take into account such changes in volume requirements.
- Shippers will be required to include the location of the requested receipt point, volume, term and rate.

[8] See 18 CFR Subpart B (§ 157.30, et seq.). See also Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, FERC Stats. & Regs., Regs. Preambles ¶ 31,174 (February. 9, 2005); 70 Fed. Reg. 8,269 (February 18, 2005) ("Order No. 2005") and Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, FERC Stats. & Regs., Regs. Preambles ¶ 31,187 (June 1, 2005); 70 Fed. Reg. 35,011 (June 16, 2005) ("Order No. 2005-A").

[9] Id. at § 157.31(a) (2006).

- The Project could be revised if the level of shipper interest indicates that the Pipeline's capacity should be adjusted.
- Bids will be evaluated on the net present value of the reservation charges offered. Shippers with the highest net present value bids will be awarded capacity. The Port Authority may reject bids below a certain rate floor.
- If the Port Authority receives more acceptable bids than available capacity, the Port Authority will consider increasing the Project's capacity. In fact the project has been designed to be able to transport up to 4 bcf/d as far as Delta Junction with very minimal additional expenditures. Consequently, the Port Authority has a huge incentive to obtain additional shipping commitments and amortize its investment in the additional expansion capacity which will also significantly reduce the tariffs.
- The Port Authority will consider bids that are non-conforming.
- The Port Authority anticipates that it will take 45 days to evaluate bids.
- The Port Authority intends to assess creditworthiness according to the standards adopted by Moody's and Standard & Poor's.
- If the bids in the open season are insufficient to justify the project, the Port Authority will talk with prospective shippers to market the capacity actively so that the Project may move forward.
- The Port Authority has exclusive access to major existing State and Federal permits for the Project. A discussion can be found in Section 4.9.

4.3.3 Precedent Agreements

The precedent agreement is under development. It will address key commercial issues as follows:

- The Port Authority will agree to construct facilities if it receives sufficiently binding commitments to support the economics of the Project and receives all necessary permitting and regulatory approvals.
- Termination rights would relate to the timing for all permitting and regulatory approvals necessary for the project and the substance of those approvals.
- With respect to termination fees, the Port Authority may seek liquidated damages from shippers that terminate. The Port Authority would return any credit support that it has received from shippers.

A preliminary draft of the precedent agreement is attached in **Error! Reference source not found.**. This preliminary draft is for illustrative purposes only and is subject to change.

4.3.4 Proposed Services and General Tariff Terms

The Port Authority plans to provide firm and interruptible transportation services. The Port Authority's terms and conditions of service are in development. The Port Authority plans to use existing interstate pipeline tariffs as a model for its terms and conditions of service.

However, the Port Authority's tariff will be modified to reflect differences in regulatory regimes and specific needs of the project. For instance, FERC requires interstate pipelines to adopt standards developed by the North American Energy Standards Board ("**NAESB**"). However, certain NAESB standards may be meaningless for a pipeline that is not part of an extensive and interconnected interstate-pipeline grid. The Port Authority intends to provide prospective shippers with a draft of its terms and conditions of service during the open season. This will allow the Port Authority to work with shippers to determine whether any changes should be made.

4.3.5 Rate Structure and Supporting Information

As will be discussed in detail in Section 4.9.3, the Pipeline portion of the Project has been determined to be non-jurisdictional for FERC. Consequently, its rates will not be subject to FERC cost-of-service ratemaking requirements.

Nonetheless, assuming that the Port Authority's rates might ultimately be regulated on a cost-of-service basis by the Regulatory Commission of Alaska ("**RCA**") (see Section 4.9.4), **Error! Reference source not found.** provides an indicative calculation of recourse rates using a FERC cost-of-service rate model.

The Port Authority notes that the Pipeline should have flexibility to offer negotiate rates with prospective customers, even if it also must offer a cost-of-service option.

The Port Authority further notes that new projects at FERC have been authorized to apply a 14% return on equity ("ROE") in their cost-of-service rates. Given that the Alaskan pipeline project would be a risky investment in comparison with recent interstate pipeline projects, the Port Authority believes that a higher return on equity may be required to attract outside investors in the Pipeline project.

4.3.6 Alternative Ratemaking Methods and Incentives

Please see Section 4.3.8 for this discussion.

4.3.7 Negotiated Rates

Even if the Pipeline were subject to FERC regulation for its rates (see Section 4.9.3 for a detailed discussion of FERC jurisdictional issues and decisions pertaining to YPC's project), the Port Authority notes that the Pipeline would have flexibility to offer negotiated rates with prospective customers, even if it also must offer a cost-of-service option.

The Port Authority anticipates that the alternative rate-making methods discussed in Section 4.3.6 above would make the Project more attractive to prospective shippers and, therefore, anticipates that the majority of shippers would enter into negotiated rate arrangements with the Port Authority.

4.3.8 Anchor Shipper Incentive Rates and Commitments to Rates for Expansion Capacity

The Project would consider alternative ratemaking methods as necessary to address the impact of cost overruns on the pipeline tariff, such as proposing a negotiated, levelized tariff to FERC. This tariff structure deviates from the standard FERC declining tariff and provides a benefit to shippers by reducing the tariff levels in the earlier years of the project. This tariff proposal can be made during the open season period, and is subject to the shippers' consent.

In addition, the Port Authority will propose a sliding scale adjustment which will vary over the life of the project to allocate the impact of any cost overruns between the shippers and the Project (see Section 4.3.11 for further discussion).

4.3.9 Commitments to In-State Service

In accordance with the requirement set forth in AS 43.90.130(12), the Port Authority will commit to provide a minimum of five delivery points for natural gas within the State of Alaska, if it is awarded a license under the AGIA.

As required under AS 43.90.130(13)(A), the Port Authority commits to offer firm transportation service to delivery points in the State of Alaska as part of the tariff regardless of whether any shippers bid successfully in a binding open season for firm transportation delivery service points in the State, and commit to offer distance sensitive rates to delivery points in this State consistent with 18 C.F.R. § 157.34(c)(8).

As required under AS 43.90.130(13)(B), the Port Authority further commits to offer distance-sensitive rates to delivery points in the State consistent with 18 C.F.R. §157.34(c)(8) (to be enforced by the RCA).

The Port Authority's approach has been to evaluate the benefits and costs of providing delivery points in-State. Beyond our voter mandate, ensuring that communities, businesses, and State and Federal governmental entities across Alaska have access to clean burning, low cost, natural gas is a guiding principle of the Port Authority. We do not want reasonably sized communities along the pipeline route to be wondering following Project start-up why they do not have access to Alaska's gas while the pipeline might run, literally, through their back yard.

One consideration that must be weighed when determining how many delivery points are installed is the balance between the investment that must be made to install a delivery point versus the expense of running natural gas spur lines. At some locations along the proposed route, it may be more cost-efficient if fewer delivery points are provided and other entities bear the expense of constructing additional miles of gas spur lines.

Provided below is a list of potential delivery points identified to date by the Port Authority. It is likely that more delivery points could be established to foster potential economic growth in areas along the pipeline route.

Toolik Lake Research Station

Operated by the University of Alaska, the Toolik Lake scientific research station is funded primarily by the National Science Foundation ("**NSF**") and operates year-round. The station relies on Number-1 diesel fuel and is expanding. University of Alaska officials are highly desirous of replacing the 49,000 gallons of Number-1 diesel they purchase annually with natural gas. NSF funding may be available to them for infrastructure upgrades that will be necessary to convert to natural gas. Scientists conducting work at the research site are highly desirous of having a fuel source that burns significantly cleaner than the Number-1 fuel oil as the pollution from the fuel oil hampers scientific research conducted in the vicinity.

Wiseman

Wiseman is a small, unincorporated, community along the Dalton Highway.

Coldfoot

Coldfoot is the location of an Alaska Department of Transportation camp and truck stop at MP 175 of the Dalton Highway. This small community operates year round and is reliant on expensive fuel oil that is trucked from Fairbanks to generate heat and electricity. The Alaska Department of Transportation is very supportive of being able to obtain gas delivery points for their road camps.

Bettles, Allakaket, Alatna

Small, adjacent communities, near the Dalton Highway. The Port Authority proposes providing one delivery point in the region.

Stevens Village, Fort Yukon

These small communities are near the proposed pipeline corridor. The Port Authority proposes providing one delivery point at the closest point of the pipeline corridor to Stevens Village.

Yukon River

This is a hub/transit point where the Dalton Highway crosses the Yukon River. ANGDA has a proposal to build infrastructure at this location to ship gas/propane to many Yukon River communities.

Fort Knox

Fairbanks Gold Mining Inc. operates Fort Knox, the largest open-pit gold mine in North America and an important contributor to the Alaska's economy. The mine uses a substantial amount of power for their year-round operation. The Port Authority is in the process of determining the most economical location for a delivery point for Fort Knox.

On possible location under consideration for a Fort Knox delivery point is Fox, Alaska – the same delivery point as for Fairbanks.

Fairbanks North Star Borough

The Fairbanks North Star Borough ("**FNSB**") is a large community of 86 thousand people that includes the City of Fairbanks, Fort Wainwright, Eielson Air Force Base ("**AFB**"), Ester, North Pole, and Fox within a borough that is the size of New Jersey. This borough will be a large consumer of natural gas in the Interior. The Port Authority envisions that the most likely delivery point for the City of Fairbanks, Fort Wainwright and the outlying Northern homes and businesses of FNSB will be in Fox, Alaska, where the pipeline infrastructure would pass closest to the City of Fairbanks.

North Pole, Moose Creek, Golden Valley Electric Association

North Pole and Moose Creek are small bedroom communities of Fairbanks. In addition, the Golden Valley Electric Association generates electrical power for the region from its North Pole facility. This generation facility includes turbines in North Pole that are designed to be able to run on natural gas.

Eielson AFB

Eielson AFB has a coal-fired power plant that is in very close proximity to the pipeline corridor. Two years ago, concern over the high costs of operating Eielson AFB led to a recommendation to the Base Realignment and Closure Commission that Eielson AFB be closed. The commission rejected the recommendation for closure, but Air Force officials are still concerned about the need to reduce costs. The more the costs of operating Eielson AFB can be reduced, the less likely it is that the base will be targeted for a closure in the future.

Eielson AFB is a key asset for the U.S. Air Force and an important economic engine for Alaska. Providing Eielson AFB with natural gas will reduce heating and electrical generation costs while also improving Eielson's air quality. Eielson officials contacted strongly support the delivery point.

Salcha, Alaska

Salcha is a distant bedroom community of Fairbanks and North Pole. A proposed delivery point will be near the Salcha Elementary School.

Harding Lake

Harding Lake is a distant community from Fairbanks and North Pole.

Pogo Mine

Pogo mine is an important new gold mine comprising about 16,700 hectares of claims and a reported gold resource of 5.6 million ounces. The mine is 85 miles east-southeast of Fairbanks on state land in the upper Goodpasture River Valley.

Delta Junction, Fort Greely, Donnelly Training Area

Delta Junction is a small, rural community. Fort Greely is a small U.S. Army base with significant energy needs. The Donnelly Training Area/complex has as many as seven hundred soldiers living in it during training exercises. U.S. Army officials who were contacted are desirous of replacing the 2.6 megawatts of electricity they purchase for the training area with low-cost natural gas.

Fort Greely Missile Defense Power Plant

This is the location of a land-based ballistic missile defense site, where a new power plant is to be constructed.

Glennallen

Glennallen is a small rural community, which will also be the delivery point for the ANGDA spur line from Glennallen to Palmer to tie into the South Central gas grid, which would provide gas to the communities and consumers in the Matanuska Valley, Peters Creek, Chugiak, Eagle River, the Anchorage area and Kenai Peninsula.

Copper Center

Copper Center is a small rural community.

Valdez

Valdez is a mid-sized community and is also the terminus of TAPS. Valdez will also be the terminus of the All-Alaska Gasline and will be the major delivery point for gas transported for liquefaction at the LNG Facilities in Valdez.

4.3.10 Commitment on Rate Treatment of State's Reimbursement

In compliance with AS 43.90.130(18) the Port Authority commits that the State reimbursement received by the Port Authority will not be included in the applicant's rate base, and shall be used as a credit against the Port Authority's cost-of-service.

4.3.11 Minimizing the Effect of Cost Overruns on Rates

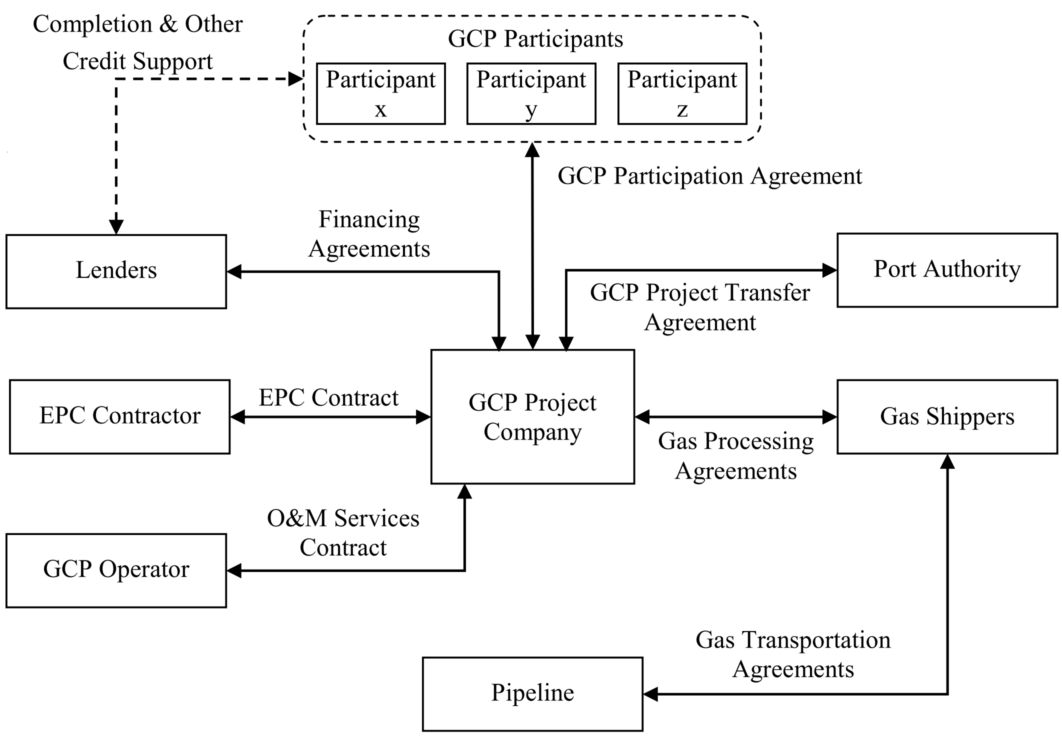
The Project will implement a range of customary methods and incentives to control Project costs and minimize the impact of cost overruns on the pipeline tariff, including: entering into fixed-price, date certain EPC contracts for the major components of the

Project, wherever possible, with limited price re-opener clauses, providing incentives for controlling costs and appointing an engineering, procurement, construction contract manager to assist in the management and coordination among the various contractors, among others. Further, the Project would consider alternative ratemaking methods, if applicable, to address the impact of higher than budgeted Project costs on transportation tariffs, as discussed in Section 4.3.8.

4.4 Commercial Plan for the GCP

It is anticipated the commercial structure of the GCP will include the agreements as described further below in this section. Figure 3 below shows a diagram illustrating the anticipated GCP commercial structure.

Figure 3 GCP Commercial Structure



The subsections below describe the key commercial agreements that are expected to be entered into with respect to the GCP.

4.4.2 GCP Participation Agreement

The GCP Participation Agreement will be entered into between the GCP Participants for the purpose of the ownership, development, construction, financing and operation of the GCP. The Port Authority is currently in discussions with a Regional Native Corporation as a potential GCP Participant. One or more of the ANS producers of natural gas, or their affiliates, may also be GCP Participants. The Port Authority may retain a percentage ownership or other interest in the GCP, if it is determined to be beneficial to the structure and economics of the Project.

The Port Authority has deferred the selection of GCP Participants and negotiation of definitive terms of the GCP Participation Agreement until after award of the License, in order to achieve the most attractive commercial terms for the provision of gas conditioning services to the Project. It is anticipated that the selection of GCP Participants and the execution of a definitive GCP Participation Agreement would be concluded prior to the commencement of the initial open season for the Project.

The GCP Project Participation Agreement will include, among other things, provisions specifying:

- the legal form of the entity that will own the GCP ("**GCP ProjCo**"), which may be a limited liability company ("LLC") or a similar entity;
- percentage shares, and voting rights of the GCP Participants;
- the governing and management structure of GCP ProjCo;
- procedures for entry of new GCP Participants and the exit of existing GCP Participants;
- procedures for cash calls to fund expenditures associated with the development, construction, financing and operation of the GCP;
- procedures for distribution of profits generated by the GCP; and
- any other provisions related to the rights and responsibilities of the GCP Participants.

4.4.3 GCP Project Transfer Agreement

Upon execution of the GCP Participation Agreement, the Port Authority and the GCP Participants would enter into a GCP Project Transfer Agreement, whereby the Port Authority would transfer to the GCP Participants, or their designee, its rights and obligations pursuant to authorizations, permits and commercial arrangements, as they relate to the GCP component of the Project, that have been acquired or entered into by the Port Authority up to the effective date of the GCP Participation Agreement.

4.4.4 Gas Processing Agreements

It is anticipated that GCP ProjCo will enter into Gas Processing Agreements with shippers of natural gas who have entered into gas transportation agreements with the Pipeline ProjCo and would require gas conditioning and processing services. Such agreements will define the terms and conditions of gas conditioning and processing services at the GCP for natural gas which will be transported on the Pipeline.

4.4.5 GCP Operations and Maintenance Services Contract

GCP ProjCo will enter into a GCP Operations and Maintenance Services Contract with an entity, which may be one of the GCP Participants or its affiliate, for the purposes of providing operating and maintenance services for the GCP.

4.5 Commercial Plan for the LNG Facilities

The Port Authority is in discussions with several companies with strong track record and industry experience in the implementation of LNG projects and the marketing of natural gas, LNG and NGLs. It is anticipated that the LNG Facilities will be owned and operated by a venture consisting of one or more of these companies and, potentially, additional parties to be selected after award of the License (the "**LNG Participants**"). The LNG Participants will enter into an LNG Participation Agreement and establish the entity that will own the LNG Project facilities ("**LNG ProjCo**"), which could be an LLC or similar entity.

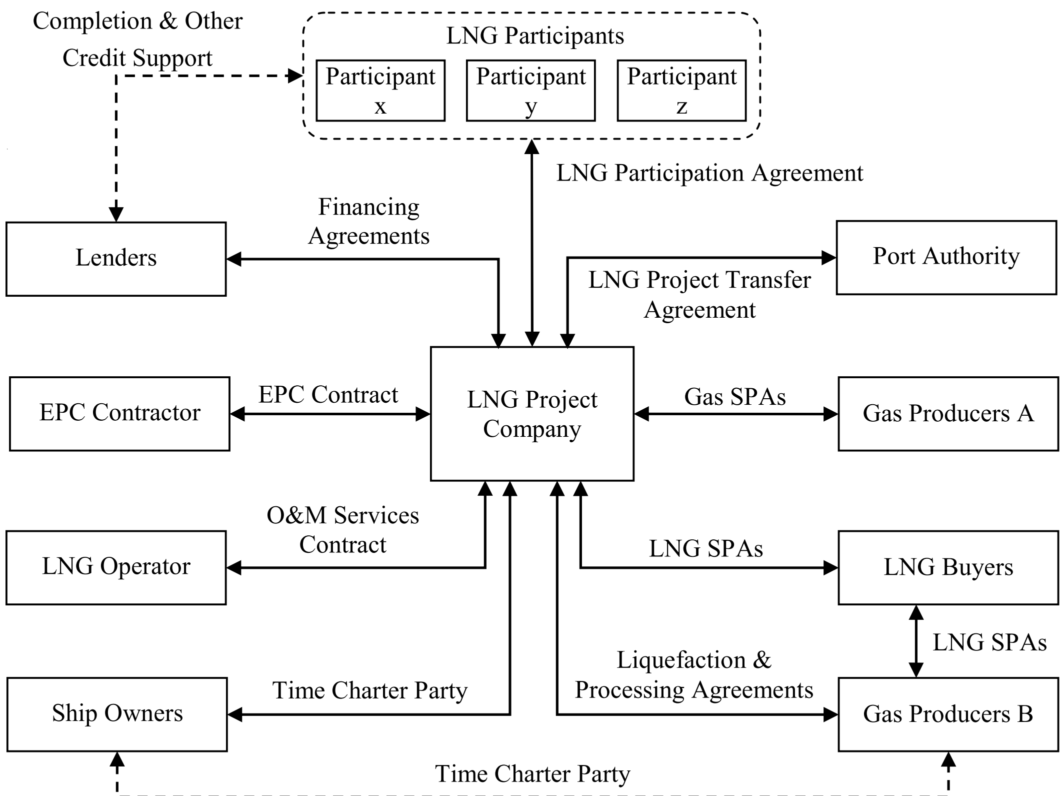
ANS producers who have arranged for transportation of natural gas on the Pipeline and wish to maintain ownership and marketing control over such gas downstream of the LNG Facilities, would enter into Liquefaction and Processing Services Agreements with LNG ProjCo, on a tolling basis, and would be responsible for marine transportation and downstream marketing and sales arrangements.

Natural gas that is not processed and liquefied at the LNG Facilities on a tolling basis pursuant to a Liquefaction and Processing Services Agreement would be purchased and marketed by LNG ProjCo and/or one or more of the LNG Participants pursuant to Gas Sales and Purchase Agreements. Sellers of natural gas under this arrangement may include ANS producers who do not have the expertise in marketing LNG in foreign markets.

The potential counterparties under (i) Liquefaction and Processing Services Agreements and (ii) Gas Sales and Purchase Agreements, and the allocation of the capacity of the LNG Facilities between these two types of commercial arrangements will be identified prior and during the initial open season.

Figure 4 below shows a diagram illustrating the anticipated commercial structure for the LNG Facility.

Figure 4 LNG Facilities Commercial Structure



The subsections below describe the key commercial agreements that are expected to be entered into with respect to the LNG Facilities.

4.5.2 LNG Participation Agreement

The LNG Participation Agreement will be entered into between the LNG Participants for the purpose of the ownership, development, construction, financing and operation of the LNG Facilities. One or more of the ANS producers of natural gas, or their affiliates, may also be LNG Participants. The Port Authority may retain a percentage ownership or other interest in the LNG Facilities, if it is determined to be beneficial to the structure and economics of the Project.

The LNG Participation Agreement will include, among other things, provisions specifying:

- the legal form of LNG ProjCo;
- percentage shares, and voting rights of the LNG Participants;
- the governing and management structure of LNG ProjCo;
- procedures for entry of new LNG Participants and the exit of existing LNG Participants;

- procedures for cash calls to fund expenditures associated with the development, construction, financing and operation of the LNG Facilities;
- procedures for distribution of profits generated by the LNG Facilities;
- any other provisions related to the rights and responsibilities of the LNG Participants.

4.5.3 LNG Project Transfer Agreement

Upon execution of the LNG Participation Agreement, the Port Authority and the LNG Participants would enter into an LNG Project Transfer Agreement, whereby the Port Authority would transfer to the LNG Participants, or their designee, its rights and obligations pursuant to authorizations, permits and commercial arrangements, as they relate to the LNG Facilities, that have been acquired or entered into by the Port Authority up to the effective date of the LNG Participation Agreement.

4.5.4 Liquefaction and Processing Services Agreements

The Liquefaction and Processing Services Agreements will be entered into between LNG ProjCo and third party shippers or producers of natural gas, including ANS producers of natural gas for the provision of liquefaction and NGL extraction services, on a tolling basis. Such agreements will include:

- specific volume requirements;
- length of term;
- tolling rates;
- "ship-or-pay" provisions;
- performance and default remedies; and
- any other provisions customary for agreements of similar nature.

4.5.5 Gas Sales and Purchase Agreements

The Gas Sales and Purchase Agreements will be entered into between LNG ProjCo, and/or one or more of the LNG Participants and sellers of natural gas, including ANS gas producers. Such sellers shall agree to sell to one or more of the LNG Project Participants, or to LNG ProjCo, natural gas transported on the Pipeline and delivered to the inlet of the LNG Facilities. The Gas Sales and Purchase Agreements will include:

- specific volume requirements;
- length of term;
- pricing arrangements based on applicable pricing indexes;
- "take-or-pay" and "supply-or-pay" provisions;
- performance and default remedies; and
- any other provisions customary for agreements of similar nature.

4.5.6 LNG Operations and Maintenance Services Contract

LNG ProjCo will enter into an LNG Operations and Maintenance Services Contract with an entity, which may be one of the LNG Participants or its affiliate, for the purposes of providing operating and maintenance services for the LNG Facilities.

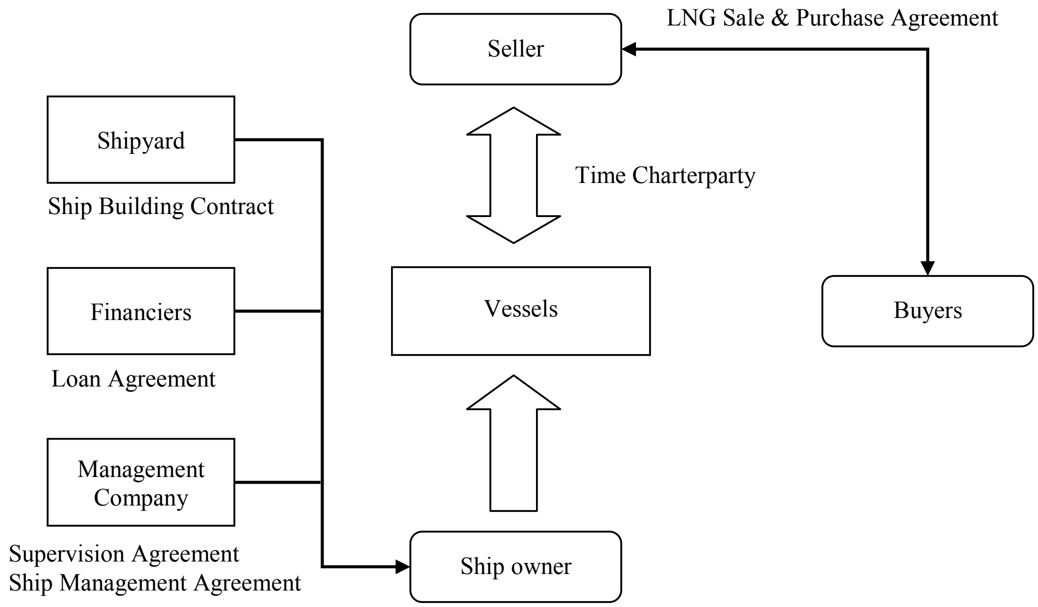
4.6 Commercial Plan for Marine Transportation Services

As described above in Section 3.5, marine transportation services for LNG and LPGs will be provided by third parties, who will be selected under a competitive tender process (the "**Ship Owner**"). It is anticipated that LNG ProjCo, and/or one or more of the LNG Project Participants will enter into marine transportation arrangements, such as long-term time charter agreements, for volumes of LNG that will be marketed by LNG ProjCo and/or one or more of the LNG Participants. As described in Section 4.5 above, such volumes of LNG will be produced from feed gas that has been purchased under Gas Sales and Purchase Agreements.

For volumes of LNG owned by third-party gas producers who have contracted with the LNG ProjCo for tolling services under Liquefaction and Processing Services Agreements and will maintain control over the marketing function themselves, the arrangement of marine transportation services will be the responsibility of such third party gas producers. It is anticipated that marine transportation for such volumes would be provided either by third party ship owners under long term charter contracts with the gas producers, or by the gas producers themselves, to the extent that they own their own tanker fleets.

Figure 5 below shows an illustration of a typical time charter structure for an LNG project supplying LNG to a buyer on a "delivered ex-ship" ("**DES**") basis, whereby the seller of LNG is responsible for marine transportation.

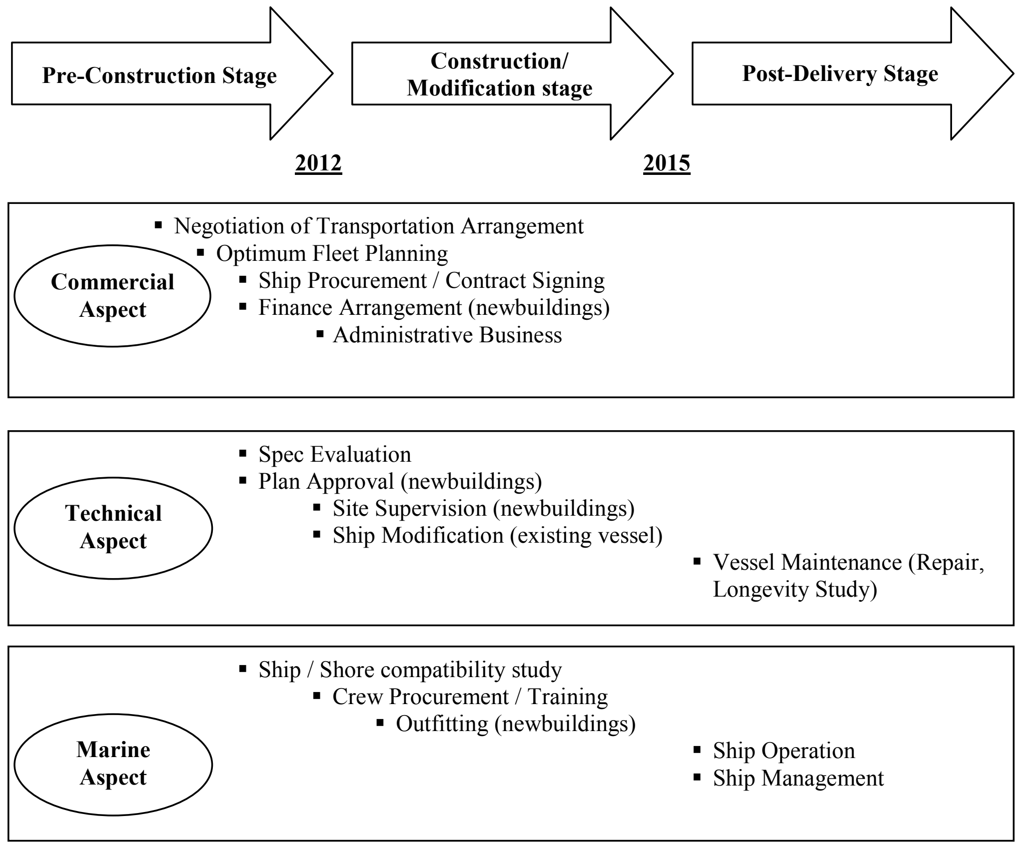
Figure 5 Indicative Time Charter Structure (DES Basis)



Under the commercial arrangement illustrated above, LNG ProjCo and/or one or more of the LNG Participants will act as the seller of LNG under LNG sales and purchase agreements with East Asian buyers, and also as the charter under the time charter party agreement ("**TCP**") with the Ship Owner. The Ship Owner will enter into: (i) shipbuilding contracts ("**SBC**") with shipyards; (ii) financing agreements with lenders to provide debt financing for the vessels; and (iii) supervision and/or ship management agreement with a management company to manage the vessels.

The process of developing the marine transportation element of the project is illustrated in Figure 6 below. As the ship construction stage takes approximately three years, the SBC will typically have to be executed approximately 34-36 months prior to vessel delivery. The Ship Owners will enter into the shipbuilding contract on the basis of an executed long term TCP with the charterer. Therefore, the TCP would typically be executed by the execution date of the SBC.

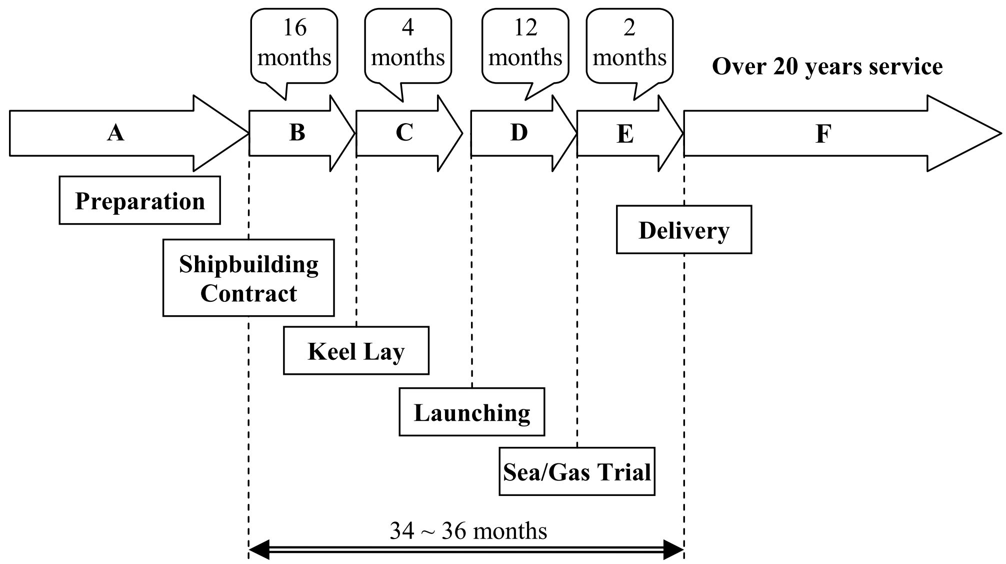
Figure 6 Marine Transportation Development Process



With an estimated Project startup date in 2015, the TCP and SBC would have to be negotiated and entered into by 2012, or approximately one year after the commencement of construction on the Pipeline, LNG Facilities and GCP.

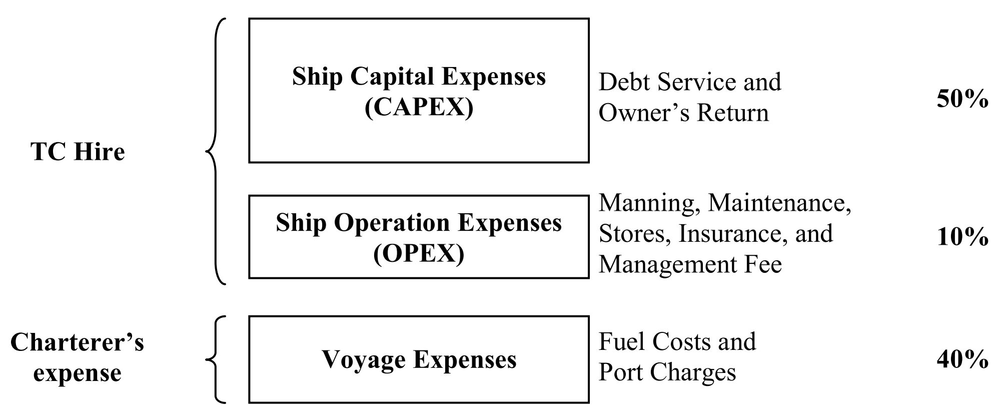
Figure 7 below shows an indicative construction schedule for LNG vessels.

Figure 7 Construction Schedule of an LNG Vessel



Under the TCP with the Ship Owner, the charter will be paying the charter hire cost for the vessels, which consists of a capital cost and operating cost component. The charter will also be incurring voyage costs, such as port charges and fuel costs. As illustrated in Figure 8 below, the capital cost component of the charter hire is typically the largest component of the marine transportation cost for newbuildings.

Figure 8 Marine Transportation Cost Components



Confidential estimates of the marine transportation costs for the Project have been provided by the MOL Companies and are attached as **Error! Reference source not found.**.

The targeted destination markets for LNG are outside of the United States and, therefore, the marine transportation element of the Project will not be subject to the requirements of section 27 of the Marine Merchant Act of 1920, commonly referred to as the Jones Act.

To the extent that in the future some amount of LNG is directed to markets in the United States that requires, the Port Authority and the LNG Participants will jointly evaluate the appropriate means for addressing any potential Jones Act concerns.

4.7 Destination Markets for LNG and NGL

The economic basis for the selection of East Asia as the targeted destination markets for LNG and LPGs is described in detail in Section 12.1.

This section provides a description of the regasification infrastructure in the targeted markets, as required under section 2.2.3.14 of the RFA.

Under the traditional LNG sales arrangements in the East Asian LNG markets, LNG is sold on a DES basis. As the buyer takes ownership of the LNG after unloading from the LNG vessel, the buyer is responsible for the provision of regasification, transportation and marketing once the LNG is sold on a "landed" basis. The seller, therefore, neither pays the cost, nor assumes the risk of regasification and downstream marketing. These customary arrangements differ significantly from those in North America, where the seller of LNG typically has to ensure that regasification and takeaway pipeline capacity has been secured.

Furthermore, regasification capacity in the East Asian LNG importing countries is ample and available in numerous terminals, with significant under-utilized spare capacities. Table 1 below shows the existing and planned regasification capacity in Japan, South Korea, and Taiwan. Based on 2006 LNG imports into Japan of approximately 60 mmta,[10] Japan alone has spare regasification capacity of approximately 130 mmta, or 68 percent.

Table 1 Regasification Capacity in Japan, South Korea and Taiwan

Name	Investor	Capacity (mmta)	Storage (1,000kl)	Start-up
Japan (existing):				
Sendai	Sendai City Gas	8.0	80	1997
Higashi Niigata	Nihonkai LNG	17.1	720	1984
Futtsu	Tokyo Electric	16.0	1,110	1985
Sodegaura	Tokyo Electric, Tokyo Gas	27.7	2,660	1973
Higashi Ogishima	Tokyo Electric	14.7	540	1984
Ogishima	Tokyo Gas	5.1	600	1998
Negishi	Tokyo Electric, Tokyo Gas	13.6	1,180	1969
Sodeshi	Shimizu LNG	6.4	177	1996
Chita Kyodo	Chubu Electric, Toho Gas	8.0	300	1977
Chita	Chita LNG	12.0	640	1983
Chita Midorihama	Toho Gas	0.8*	200	2001
Yokkaichi LNG Center	Chubu Electric	8.8	320	1987

[10] BP Statistical Review of World Energy June 2007.

Name	Investor	Capacity (mmta)	Storage (1,000kl)	Start-up
Yokkaichi	Toho Gas	0.6	160	1991
Kawagoe	Chubu Electric	7.7	480	1997
Senboku 1	Osaka Gas	2.5	180	1972
Senboku 2	Osaka Gas	13.1	1,585	1977
Sakai	Sakai LNG	2.7	420	2006
Himeji Joint	Osaka Gas, Kansai Electric	4.0	1,440	1984
Himeji LNG	Osaka Gas	8.3	520	1979
Mizushima	Chugoku Electric, Nippon Oil	0.8*	160	2006
Hatsukaichi	Hiroshima Gas	0.4	170	1996
Yanai	Chugoku Electric	2.4	480	1990
Oita	Oita LNG	5.1	460	1990
Tobata	Kitakyushu LNG	6.4	480	1977
Fukuoka	Saibu Gas	0.6	70	1993
Nagasaki	Saibu Gas	0.11*	35	2003
Kagoshima	Nihon Gas	0.1	86	1996
Japan (existing):		**193.0**	**14,553**	
Japan (planned):*				
Wakayama	Kansai Electric	N.A.	N.A.	N.A.
Joetsu	Chubu Electric, Tohuku Electric	N.A.	N.A.	N.A.
Omaezaki	Chubu Gas, Tokai Gas, Suzuyo	N.A.	N.A.	2010
Sakaide	Shikoku Electric	0.40	N.A.	2010
Kumamoto	Saibu Gas	N.A.	N.A.	N.A.
Nakagusuku	Okinawa Electric	0.70	N.A.	2010
Japan (planned):		**1.1**	**N.A.**	
Japan (existing + planned):		**194.1**	**14,553**	
S. Korea (existing):				
Pyeongtaek	KOGAS	13.3	1,000	1986
Inchon	KOGAS	22.4	2,480	1996
Tongyoung	KOGAS	5.0	980	2002
Gwangyang	POSCO	1.7*	200	2005
South Korea (existing):		**19.1**	**4,660**	
South Korea (planned):*				
Gunsan	GS Caltex	1.5	N.A.	N.A.
Cheju	KOGAS	N.A.	N.A.	2012
(4th Terminal)	KOGAS	N.A.	N.A.	2013
(5th Terminal)	KOGAS	N.A.	N.A.	N.A.
South Korea (planned):		**1.5**	N.A.	

Name	Investor	Capacity (mmta)	Storage (1,000kl)	Start-up
South Korea (existing + planned):		**20.6**	**4,660**	
Taiwan (existing):				
Yungan	CPC	7.5	690	1990
Taiwan (existing):		**7.5**	**690**	
Taiwan (planned):*				
Taichung	CPC	1.7	N.A.	2007
Taiwan (planned):		**1.7**	N.A.	
Taiwan (existing + planned):		**9.2**		
Total Japan, S. Korea, and Taiwan (existing + planned):		**223.9**	**19,903**	

Sources: EIA, The Global Liquefied Natural Gas Market: Status and Outlook 2003, except where marked with an asterisk.
** The Institute of Energy Economics, Japan. "Natural Gas and LNG Supply/Demand Trends in Asia Pacific and Atlantic Markets (2006), September 2007.*

Export permitting for LNG exported from the Project is discussed in detail in Section 4.9.1.

4.8 Plan for NGL Processing and NGL Markets

As discussed in Section 3.6 above, propane and butane from gas transported to Valdez for liquefaction will be extracted at the fractionation facilities which will be an integral part of the LNG Facilities. There will be no separate NGL processing charge for LPG extraction, and terms and conditions of service will be governed by the commercial arrangements with respect to liquefaction, as described in Section 4.5 above.

As the production of LPGs at the LNG Facilities will be a by-product of LNG production, the commercial arrangements for LPGs will parallel those for LNG. As in the case of LNG marketing, LPGs will be marketed either by one or more of the LNG Project participants, or by ANS gas producers who wish to maintain control over the marketing function of gas and LPGs, as described for the case of LNG in Section 4.5 above.

As described in Section 4.5 above, the Port Authority is in discussions with several companies with significant industry experience regarding their potential role in the as LNG Participants. These companies have also expressed a strong interest in participating in the marketing functions for LPGs.

For a description of the economic basis for the targeted markets for propane and butane, please refer to Section 12.1.5.

4.9 Regulatory Plan

4.9.1 Regulatory Approvals

The following is a list of major regulatory approvals associated with the project:

Table 2 Major Permits Required for the Project

Agency	Permit/Approval
FEDERAL	
U.S. Department of Energy (DOE)	Section 3 of the Natural Gas Act (Approval of LNG Export)
Federal Energy Regulatory Commission (FERC)	Section 3 of the Natural Gas Act (Approval of Site of LNG Export)
U.S. Environmental Protection Agency	Spill Prevention, Containment and Cleanup Plan (CWA, 33 U.S.C. 1321(j))
U.S. Department of the Army Corps of Engineers (USACE)	Section 404 (CWA)/Section 10 (Rivers and Harbors Act)
U.S. Coast Guard (USCG)	Letter of intent must be filed (33 CFR Part 127)
U.S. Coast Guard (USCG)	Waterway Suitability Assessment
U.S. Department of Transportation (DOT)	Petition for Approval (49 CFR Part 193) Federal Safety Standards
U.S. Fish and Wildlife Service (FWS)	Section 7 of Endangered Species Act Consultation
National Marine Fisheries Service	Section 7 of Endangered Species Act Consultation
STATE/LOCAL	
	Air Permit
	Notice of Intent (NOI) to Discharge Stormwater Associated with Construction Activity
	LPDES Notice of Intent (NOI) to Discharge Hydrostatic Test Wastewater
	Water Quality Certification
	Coastal Zone Management Act Consistency Determination
	Section 106 of the National Historic Preservation Act

The Port Authority will benefit from the substantial permitting work that was undertaken by YPC. It took 11 years from YPC's initial federal right-of-way application filed in May of 1984 until FERC's approval of the place of export site in 1995. During that period of time, YPC expended in excess of $70 million to obtain the State and Federal Project permits and authorizations described herein. This creates a significant time advantage associated with this Project, which would allow construction to commence years ahead of a project without the same level of regulatory approvals and environmental data.

The major approvals and rights of way acquired by YPC that will be used and updated by the Port Authority are as follows:

1. <u>Presidential Finding:</u> Exports of natural gas from Alaska to nations other than Canada or Mexico require a Presidential finding under the Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. § 719 et seq. ("**ANGTA**"). The finding was promulgated in January 1988. The period of time it took to secure this finding was 3 years and 8 months. The document is attached herein as **Error! Reference source not found.**.

2. <u>State of Alaska Coastal Zone Consistency Determination (Tier 1):</u> The original Trans Alaska Gas System ("**TAGS**") project obtained in 1988 a favorable determination that the general project scope was consistent with the standards of the Alaska Coastal Management Program. The period of time it took to obtain this permit was 10 months. The document is attached herein as **Error! Reference source not found.**.

3. <u>Bureau of Land Management/U.S. Army Corps of Engineers TAGS FEIS:</u> The U.S. Bureau of Land Management ("**BLM**") and the Army Corps of Engineers prepared a final environmental impact statement ("**FEIS**") for the TAGS pipeline project in 1988. The Port Authority plans to update this FEIS. The period of time it took to obtain this permit was 4 years and 5 months. The document is attached herein as **Error! Reference source not found.**-4.

4. <u>Ahtna Corporation Right-of-Way Agreement:</u> In 1988, the developer of the TAGS project entered into a right-of-way agreement with the Ahtna tribe that sets forth broad terms for the use of right-of-way across Ahtna tribal lands. The document is attached herein as **Error! Reference source not found.** (Confidential).

5. <u>BLM Right-of-Way Agreement:</u> This right-of-way agreement was also entered into in 1988. The Port Authority intends to update this agreement. The period of time it took to obtain this permit was 4 years and 5 months. The document is attached herein as **Error! Reference source not found.**G-6.

6. <u>State of Alaska Conditional Right-of-Way Lease:</u> As with the BLM right-of-way agreement, the Port Authority intends to update this agreement. The period of time it took to obtain this permit was 2 years and 9 months. The document is attached herein as **Error! Reference source not found.**.

7. <u>Department of Energy Export Authorization:</u> In 1989, the U.S. Department of Energy issued an order authorizing the export of gas to Japan, South Korea, and Taiwan. The Port Authority intends to export gas from its project to these same three countries. The period of time it took to obtain this authorization was 2 years and 11 months. The document is attached herein as **Error! Reference source not found.**.

8. <u>FERC Authorization of Anderson Bay LNG Facility:</u> In 1995, FERC authorized the construction and operation of a LNG facility at Anderson Bay. The Port Authority intends to update environmental data for FERC. The period of time it

took to obtain this authorization was 7 years and 3 months. The document is attached herein as **Error! Reference source not found.**.

9. Air Quality Construction Permit: The Alaska Department of Environmental Conservation issued in 1997 a permit that allows for air pollutant discharges during construction and operation of the LNG facility. The Port Authority intends to supplement the permit with current and additional data. The period of time it took to obtain this permit was 8 years. The document is attached herein as **Error! Reference source not found.**.

A detailed YPC White Paper, which describes each of the above permits and authorizations, as well as the background and process of obtaining them, is attached in **Error! Reference source not found.**.

4.9.2 Rights-of-Way

The Pipeline will utilize the Federal Right-of-Way Grant issued to YPC on October 17, 1988 and pursuant to the State of Alaska Conditional Right of Way Lease issued to YPC effective December 10, 1988. Copies of these documents are attached in **Error! Reference source not found.** and **Error! Reference source not found.**, respectively.

4.9.3 Commitments for FERC-Certificated Project

Summary

The jurisdiction of FERC and DOE over the Project has been clearly articulated through a series of final Federal agency orders issued to YPC. Briefly, to the extent FERC and DOE jurisdiction applies to the Project, the requisite authorizations have been obtained and are described in more detail below. Neither FERC nor DOE have exercised jurisdiction over the Pipeline. It will instead be covered by a certificate of public convenience and necessity issued by the RCA under Alaska's Pipeline Act.

Detailed Description

Section 7 of the Natural Gas Act, 15 U.S.C. § 717 et seq. ("**NGA**"), governs interstate natural gas sales and transportation. Section 3 of the NGA governs imports and exports of natural gas. Section 3 authority has been interpreted broadly to require authorization of: (a) the import or export itself; (b) the place of import or export; and (c) the siting, construction, and operation of the associated facilities. The DOE generally has the authority to regulate imports and exports of natural gas, while FERC has authority to approve the siting, construction and operation of import and export facilities.

In 1986, YPC filed a petition with FERC describing its project and asking it to declare what NGA jurisdiction, if any, FERC had over the project. In response, FERC issued a Declaratory Order[11] stating that it (a) has no section 7 jurisdiction over any aspect of the

[11] Yukon Pacific Corporation, 39 FERC ¶ 61,216 (1987) at 758. A copy of this document is attached as Appendix G-1, along with FERC's order denying rehearing, 40 FERC ¶ 61,164 (1987).

YPC project; (b) has, and will exercise, section 3 jurisdiction over the siting, construction and operation of the LNG plant; and (c) may have, but will not exercise, section 3 authority over the siting, construction, and operation of the pipeline facilities. FERC also pointed out that selling and transporting gas beyond Alaska's border to a foreign country did not constitute interstate commerce within the meaning of the NGA.[12]

YPC did not include a gas conditioning plant and related facilities in its definition of a project, as it assumed the responsibility for constructing and operating the GCP would lie with the ANS producers. Therefore, YPC did not address in its petition the issue of what jurisdiction, if any, FERC would have over such a facility. However, FERC noted that if YPC altered its plans and shared ANGTA project pipeline facilities, the question of section 7 jurisdiction would have to be reexamined.[13] Nonetheless, as discussed below, DOE subsequently limited FERC jurisdiction over shared facilities except as necessary to ensure that YPC pays its part of the costs of any shared facilities.

With regard to section 3 of the NGA, FERC affirmed that it had authority to approve the place of export and that it may have section 3 authority to approve or disapprove the siting, construction and operation of the gas pipeline facilities connecting the Valdez terminal to the ANS.[14] However, FERC decided the facts did not warrant the exercise of such authority because an export project has no economic consequence to U.S. ratepayers.[15]

In light of FERC's Declaratory Order, YPC filed: (a) an application with DOE seeking section 3 authorization to export an average of 14 mmta of LNG to Asia over a 25-year term; and (b) an application with FERC seeking section 3 authorization to site, construct, and operate its LNG plant at Anderson Bay, Alaska.

In 1989, DOE issued its Order No. 350 approving YPC's export request.[16] DOE declared that no cost of the Project may be recovered from U.S. consumers (except in the event that sales and transportation services are provided within Alaska). It also exercised its "plenary" section 3 authority under the NGA to prohibit YPC "from taking any action that would compel a change in the basic nature and general route of an ANGTA project or otherwise prevent or impair in any significant respect its expeditious construction and operation."[17] This condition applies to all direct and support facilities of the Project, including the GCP, but not to the gas reserves.[18] The order placed the burden on the

[12] Id.

[13] Id. at 756.

[14] Id. at 758.

[15] Id.

[16] Yukon Pacific Corporation, DOE Opinion and Order No. 350, "Order Granting Authorization to Export Liquefied Natural Gas From Alaska," 1 FE ¶ 70,529 (1989). A copy of this document is attached as Appendix G-8, along with "Order Denying Rehearing Requests and Modifying Prior Order for Purposes of Clarification," 1 FE ¶ 70,303 (1990).

[17] Id. at 71, 142.

[18] Id.

ANGTA project sponsors to demonstrate any adverse effects, and warned that the condition should not be used to delay the Project unnecessarily.[19]

Further, DOE limited FERC's jurisdiction over the LNG export project to facilities it shares with another project over which FERC has interstate commerce jurisdiction, such as a shared gas conditioning plant: "[FERC] shall only exercise [its delegated NGA] authority over the export project to the extent necessary to ensure that the shared facility is constructed and operated in accordance with FERC's regulations . . . [and] the FERC shall have no other authority over Yukon Pacific's export project, including its rates, except to the extent necessary to ensure that Yukon Pacific pays its part of the costs of any shared facilities."[20]

In 1995, FERC approved Anderson Bay as the site for the Project's LNG plant and marine terminal.[21] The approval was based primarily upon the considerations and findings of the export site's FEIS.[22] FERC concluded that siting the LNG plant and associated facilities at Anderson Bay is not inconsistent with the public interest and would result in a limited adverse environmental impact during construction and operation.[23] The approval imposes a number of environmental conditions and mitigation measures which are set forth in an appendix to the Order.[24] In accordance with DOE's Order 350, the FERC FEIS considered only the facilities at the Anderson Bay Site, and not the non-jurisdictional Project pipeline.[25]

4.9.4 Commitments for RCA-Certificated Project

As noted, FERC and DOE have disclaimed any FERC jurisdiction over the Pipeline because the Project does not involve interstate commerce. As there will not be FERC certification, expansion and ratemaking oversight for the Pipeline, except to the extent there are facilities shared with a jurisdictional FERC project, the RCA has primary jurisdiction over these activities under the State of Alaska's Pipeline Act, AS 42.06.010 et seq. (the "**Pipeline Act**").

Pursuant to AS 43.90.130(4), the Port Authority expects to apply in 12 to 24 months of License award (and will apply no later than 36 months from License award) to the RCA, as a person that will be a "North Slope natural gas pipeline carrier" under AS 42.06.240, for a certificate of public convenience and necessity to authorize the construction and operation of the Pipeline in compliance with the requirements of the Pipeline Act.

[19] Id.

[20] Id. at 71, 144.

[21] Yukon Pacific Company L.P., "Order Granting NGA Section 3 Authorization for the Siting, Construction, and Operation of LNG Facility," 71 FERC ¶ 61,197 (1995). A copy of this document is attached as Appendix G-11, along with "Order Denying Rehearing," 72 FERC ¶ 61,226 (1995).

[22] Yukon Pacific LNG Project, Final Environmental Impact Statement, FERC Office of Pipeline Regulation (1995).

[23] Id. at 61, 699.

[24] Id. at 61, 708-714.

[25] 71 FERC at 61, 699.

Additionally, in accordance with AS 43.90.130(4)(A), the Port Authority expects to conclude a binding open season consistent with the requirements of AS 42.06 no later than 18 to 24 months after License award. The Port Authority will conclude a binding open season consistent with the requirements of AS 42.06 no later than 36 months after License award.

4.10 Local Project Headquarters Plan

The Port Authority believes that Fairbanks is the best location for the Project's headquarters. It is important to the Port Authority that the Project headquarters be located in a municipality through which the pipeline traverses. Additionally, Fairbanks is located midway between the GCP in Prudhoe Bay and the LNG Facilities in Valdez.

5. Execution Plan

5.1 Project Execution Plan

A Project Execution Plan was developed for the Port Authority by Bechtel under the EPC Study, attached herein as **Error! Reference source not found.**T.

For a discussion of access to updated detailed technical information related to the Port Authority's Application, please refer to Section 7.2.

5.2 Capital Cost Management Plan

For a discussion of access to updated detailed technical information related to the Port Authority's Application, please refer to Section 7.2.

5.3 Project Labor Agreement

The Port Authority is pleased to commit to a Project Labor Agreement for the Project. The Port Authority and appropriate labor representatives by attached signed Letter of Intent, Appendix MM, have committed as follows.

- Use of modernized technology with proven results of quality and integrity to increase productivity and efficiency.
- Incorporation of "pre-job" meetings where all aspects of a particular work process are explained and jurisdictional assignments are made; thus lessening the opportunity for workplace disruptions due to mis-assignments.
- Bright lines established for work done under the auspices of the building trades and work under the auspices of the pipeline crafts.
- Use of composite crews where appropriate.
- Development of a formula to assure that wage and benefits and other economic factors are known for the duration of the project.
- Incorporation of methods for complying with Sections 28 & 29 of the Right of Way Statutes which govern the authority to operate within the ROW. Including incorporation of language included in the current Labor Agreement with the Alyeska Pipeline Service Company maintenance and construction contractors which has been highly successful in providing career opportunities to Alaskan Natives.
- While the Letter of Intent identifies the intention of the parties to utilize the original TAPS Project Labor Agreement as a template; the parties recognize that the following areas either were originally not recognized or were recognized but not deemed important. We intend to craft language to:

- Allow pre-employment drug and alcohol testing;
- Treat safety as a number one priority;
- Allow for background checks;
- Deal with HIRD issues (harassment, intimidation, retaliation, and discrimination); and
- Maximum use of hiring hall procedures to assure that qualified Alaska/local hire is accomplished to the fullest extent possible under law.

5.3.1 Alaska Hire

AS 43.90.130(15)(A) requires a commitment to "hire qualified residents from throughout the state for management, engineering, construction, operations, maintenance, and other positions on the proposed project." Under the terms of a negotiated Project Labor Agreement, the Port Authority commits to hiring qualified residents of the State of Alaska with a "state resident preference" for all available positions in the management, engineering, construction, operations, and maintenance phases of the project, to the greatest extent allowed by law.

AS 43.90.130(15)(B) requires a commitment to "contract with businesses located in the state." The Port Authority will advertise, procure and contract for project development, construction, operation and maintenance, with preference to qualified and capable businesses located in the state, to the greatest extent allowed by law.

AS 43.90.130(15)(C) requires a commitment to "establish hiring facilities or use existing hiring facilities in the state." Under the terms of a negotiated Project Labor Agreement, the Port Authority commits to utilizing existing hiring facilities within the state, and will establish additional hiring facilities within the "project headquarters" as necessary.

AS 43.90.130(15)(D) requires a commitment to "use, as far as is practicable, the job centers and associated services operated by the Department of Labor and Workforce Development and an Internet-based labor exchange system operated by the state." Under the terms of a negotiated Project Labor Agreement, in addition to the pipeline building trades training and hiring centers located within the state, the Port Authority shall use the job centers and associated Alaska Department of Labor and Workforce Development services, including the use of an internet-based labor exchange system operated by the state for the recruitment and hire of project personnel.

Licensee and appropriate labor representatives by attached signed Letter of Intent also commit to the following.

- Maximum use of hiring hall procedures to assure that qualified Alaska/local hire is accomplished to the fullest extent possible under law.

- Identifying organized Alaskan Contractors for contracts or subcontracts on this project by working with contractor associations such as the Alaskan—Associated General Contractors, National Electrical Contractors Association, & the National Mechanical Association.

- Continued use of hiring halls, both virtual and mortar/bricks, which currently cover the entire State of Alaska.

- Continued partnership with Alaska Works to identify and train journey and apprentice workers in rural and urban Alaska. Participation to as full extent as appropriate with AK DOL programs existing today and working with the Department in developing processes and programs in the future.

- Alaska hire to emphasize training the Alaskan workforce for the next generation. Recruitment, classroom training and on-the-job experience to take place for pre-construction infrastructure, construction undertaken by the licensee under AGIA, maintenance of operational structures and pipelines, and training for opportunities post construction not covered under this PLA. Recruitment to emphasize rural Alaskans, K-12 and post secondary schools and institutions. Additional emphasis on our helmets to hardhats program to develop construction career opportunities for returning veterans.

6. Operations Plan

6.1 Expansion

6.1.1 Market Assessment

Consistent with AS 43.90.130(5), following the first binding open season, the Port Authority will assess the market demand for additional pipeline capacity through public nonbinding solicitations or similar means. Such solicitations of interest shall:

(a) be conducted at least every two years after the conclusion of the first binding open season;

(b) be pubic and provide at least 30 days' prior public notice of each non-binding solicitation of interest through methods reasonably calculated simultaneously to notify all interested parties, including posting on internet web sites, press release and direct mail notification and other advertising;

(c) set forth the next reasonable engineering increment of capacity, consistent with AS 43.90.130(6)(B);

(d) contain the Port Authority's good faith estimate of rates for the next reasonable engineering increment of expansion capacity as well as a larger expansion utilized rolled in rates to the levels required by AS 43.90.130(7);

(e) set forth a good faith estimate of how long it will take to place into service the next reasonable engineering increment of capacity;

(f) contain provisions that permit creditworthy prospective shippers to make binding commitments for expansion capacity in a binding open season to be conducted promptly by the Port Authority subsequent to the nonbinding solicitation of interest; and

(g) commit the Port Authority to promptly and diligently pursue a binding open season for expansion capacity to the extent that the expressions of interest demonstrate a market demand on commercially reasonable terms by creditworthy shippers that equals or exceeds the next reasonable engineering increment of capacity, as defined in AS 43.90.130(6)(B).

The Port Authority will not, in a binding open season conducted after the nonbinding solicitation of interest, require: (a) a prospective shipper to agree to any particular rate (other than the rate previously disclosed); or (b) an existing shipper to pay any rate for a capacity expansion prior to the date that new expansion facilities go into service.

6.1.2 Expansion Terms

In compliance with AGIA, the Port Authority commits to expand the Project in reasonable engineering increments and on commercially reasonable terms that encourage exploration and development of gas resources in Alaska, with “commercially reasonable terms” and “reasonable engineering increments” having the meaning set forth in AS 43.90.130(6).

The Port Authority shall commit to promptly and diligently pursue all regulatory approvals upon the receipt of acceptable binding commitments for expansion capacity, and commit to promptly and diligently proceed to expand the Project at a reasonable engineering increment sufficient to satisfy all demand for expansion capacity so long as: (a) additional revenue, if any, from existing transportation contracts on the Project, plus the projected revenue from binding expansion capacity commitments, cover the costs of the expansion (including fuel costs and a reasonable return on capital as authorized by the RCA, as applicable); and (b) the Port Authority’s ability to recover the costs of existing facilities is not impaired.

6.1.3 Rolled-in Rates Commitment

Consistent with AS 43.90.130(7) the Port Authority:

(A) will propose and support the recovery of mainline capacity expansion costs, including fuel costs, from all mainline system users through rolled-in rates as provided in (B) and (C) of this Section or through a combination of incremental and rolled-in rates as provided in (D) of this Section;

(B) will propose and support the recovery of mainline capacity expansion costs, including fuel costs, from all mainline system users through rolled-in rates if the rolled-in rates would increase the rates: (i) not described in (ii) of this subsection by not more than 15 percent above the initial maximum recourse rates for capacity acquired before commercial operations commence (in this sub-section, “initial maximum recourse rates” means the highest cost-based rates for any specific transportation service set by the RCA when the pipeline commences commercial operations); (ii) by not more than 15 percent above the negotiated rate for pipeline capacity on the date of commencement of commercial operations where the holder of the capacity is not an affiliate of the owner of the pipeline project (for the purposes of this sub-section, “negotiated rate” means the rate in a transportation service agreement that provides for a rate that varies from the otherwise applicable cost-based rate, or recourse rate, set out in a gas pipeline's tariff approved by the RCA); or (iii) for capacity acquired in an expansion after commercial operations commence, to a level that is not more than 115 percent of the volume-weighted average of all rates collected by the project owner for pipeline capacity on the date commercial operations commence;

(C) will, if recovery of mainline capacity expansion costs, including fuel costs, through rolled-in rate treatment would increase the rates for capacity described in (B) of this paragraph, propose and support the partial roll-in of mainline expansion costs, including fuel costs, to the extent that rates acquired before commercial operations commence do not exceed the levels described in (B) of this Section;

(D) may, for the recovery of mainline capacity expansion costs, including fuel costs, that, under rolled-in rate treatment, would result in rates that exceed the level in (B) of this Section, propose and support the recovery of those costs through any combination of incremental and rolled-in rates;

(E) will not enter into a negotiated rate agreement that would preclude the applicant from collecting from any shipper, including a shipper with a negotiated rate agreement, the rolled-in rates that are required to be proposed and supported by the applicant under (B) of this Section or the partial rolled-in rates that are required to be proposed and supported by the applicant under (C) of this Section.

6.1.4 General Expansion Provisions

The pledge to "promptly and diligently pursue" binding open seasons, regulatory approvals and expansions, as used in this subsection, means that the Port Authority shall act in a manner that is commercially reasonable in the interstate gas pipeline industry in the United States with respect to timing and execution of relevant actions. A shipper is deemed "creditworthy" if it satisfies the creditworthiness standards for the Project's applicable tariffs. For expressions of interest and expansions undertaken prior to regulatory approval of such standards, creditworthiness shall be determined according to the standards the Port Authority applies in its initial binding open season.

The Port Authority will file, as part of its tariff, its determination of the reasonable engineering increment of capacity based on the design of the Project prior to project sanction and each time the design capacity of the Project changes due to modifications of the facilities or operation of the pipeline (other than normal day-to-day changes in pipeline operations). For purposes of determining the reasonable engineering increment of capacity that can be added by the addition of pipe (commonly referred to as "looping"), the Port Authority shall base its calculations on: (1) the addition of a full valve section based on the original pipeline mainline valve locations; and (2) pipe diameter that would be required were a full loop of the pipeline to be undertaken.

In addition to the above express expansion commitments made by the Port Authority pursuant to AGIA, the Pipeline will be an ANS natural gas pipeline carrier subject to RCA expansion, enlargement or extension under AS 42.06.320(d) if the RCA determines:

(1) a person making a request for expanded, enlarged, or extended service by a North Slope natural gas pipeline carrier has made a firm contractual commitment to the ANS natural gas pipeline carrier to transport North Slope natural gas; and

(2) the expansion, enlargement, or extension will not result in (A) substantial injury, including economic injury, to the North Slope natural gas pipeline facility or its customers; (B) substantial detriment to the services furnished by the ANS natural gas pipeline facility; or (C) the creation of safety hazards.

7. Project Cost Estimate

7.1 Cost Estimate for Development Phase

The Port Authority has estimated development period costs, including project management, regulatory, legal, financial, general and administrative and other development costs for the period from the award of an AGIA license to final investment decision for the Project to be approximately $400 million, excluding FEED, which is currently estimated to be an additional $213 million. Such estimate has been prepared on the basis of the experience of other projects of comparable scope and nature, on the basis of a percentage of estimated total project capital cost.

Certain specific items of development period expenditures include:

- Front end engineering and design: For a discussion of access to detailed technical data related to the Port Authority's Application, please refer to Section 7.2 below.
- Regulatory and permitting activities: For work associated with updating and/or obtaining major permits in addition to the permits currently held by YPC, as described in Section 4.9.1, the Port Authority estimates incurring costs in the range of $2-3 million.
- Rights-of-way acquisition and environmental requirements would be included in the work described in the paragraph above.

7.2 Cost Estimate for Execution Phase

In early June 2007, the Port Authority assembled and began working with a consortium or prospective Project partners to facilitate the submittal of an All-Alaska Gasline bid under the AGIA. Members of the consortium included a major North American pipeline and a major gas producing company with worldwide LNG experience.

Fairly early into that process, the prospective consortium decided it was in their best interest to submit an AGIA application separate from the Port Authority. At that time, the Port Authority made the decision to grant the prospective consortium's request to have unrestricted access to the approximately $8 million worth of work performed by the Bechtel for the Port Authority since 1999. It was agreed that if the consortium members decided to not submit an application under AGIA, they would immediately make available to the Port Authority all data accumulated for their bid including various bid drafts as well as all work performed by Bechtel on their behalf.

In mid-October of 2007, one of the prospective partners chose to withdraw from the role as a named applicant under the AGIA application. The Port Authority has been informed by the remaining member of the consortium of their intention to continue with the preparation of an application for submittal under AGIA. The Port Authority understands that Bechtel has entered into arrangements that preclude its ability to working with another applicant while engaged by this remaining prospective applicant.

Based on prior discussions, the Port Authority anticipates that the technical work performed by Bechtel for this other prospective applicant is virtually identical in scope to the work that the Port Authority would have requested Bechtel to perform in the absence of an alternative applicant.

The Port Authority, therefore, herein incorporates all cost estimates and other technical work performed by Bechtel for the other prospective applicant by reference.

8. Project Schedule

8.1 Schedule for Development Phase

For a discussion of access to updated detailed technical information related to the Port Authority's Application, please refer to Section 7.2.

8.2 Schedule for Execution Phase

A schedule for the execution phase was developed under the Project execution plan included in the EPC Study performed by Bechtel, attached herein as **Error! Reference source not found.**.

For a discussion of access to updated detailed technical information related to the Port Authority's Application, please refer to Section 7.2.

9. Risk Assessment and Mitigation

9.1 Open Season and Firm Transportation Commitments

Since the Port Authority's Project is sized at 2 bcf/d, it does not share the risks of larger projects associated with: (a) finding additional ANS gas reserves; (b) AOGCC Rule 9 offtake limits; or (c) delays in Point Thomson gas offtake that may be necessary for gas cycling.

Additionally, the Port Authority views open season and firm transportation risk from Point Thomson as low because, as discussed in Section 15, the State is in the position to dictate the terms of gas commitment and sale (subject to AOGCC determinations on cycling) in the releasing of the Point Thomson acreage.

Consequently for the Port Authority's Project, risk relating to an open season and firm transportation commitments derive largely from the chance Prudhoe Bay Unit working interest owners will not commit gas to the Project once Licensed. The Port Authority has demonstrated in the Point Thomson Unit proceedings that it has the will and expertise to help the State enforce its legal rights. In that vein the Port Authority is willing, upon request by the State, to share in confidence the comprehensive legal strategy it has developed to insure Prudhoe Bay gas commitment to a Licensed Project. However, at this time the Port Authority does not view sharing this plan publicly as in the best interests of the Project or the State.

9.2 North Slope GCP

As described above in Section 3.3, the Port Authority is in discussions with the Regional Native Corporation regarding the building, owning and operation of the GCP. The Corporation's experience and familiarity with the Alaska would provide a significant mitigant for technical and operational risks associated with the GCP.

For a discussion of access to detailed technical data related to the Port Authority's Application, please refer to Section 7.2.

9.3 Permits for LNG Export, Shipping, Import

Exports of natural gas from Alaska to nations other than Canada or Mexico requires a Presidential Finding under the Alaska Natural Gas transportation Act of 1976, 15 USC 719 et.seq. ("**ANGTA**"). YPC applied for such a Presidential Finding to be able to export LNG from Valdez and such authorization was issued to YPC in January 1988.

Additionally, in 1988, the U.S. Department of Energy issued an order authorizing the export of gas to Japan, South Korea and Taiwan. This export license is for a period of 25 years at 14 million tons annually. The 25 year clock begins upon the first shipment of LNG from Valdez. The Port Authority intends to export LNG from its Valdez terminal to these same three countries.

The target destinations for the LNG from Valdez are outside the United States and therefore the marine transportation element of the Project will not be subject to the requirements section 27 of the Marine Merchant Act of 1920, commonly referred to the Jones Act. Please refer to section 4.6 for additional details of the commercial plan for marine transportation services.

9.4 Availability and Costs of Labor Resources and Construction Equipment

For a discussion of access to detailed technical data related to the Port Authority's Application, please refer to Section 7.2.

9.5 Rights-of-Way Acquisition and Environmental Requirements

Federal Pipeline ROW Grant. A Federal ROW grant was issued to YPC on October 17,1988 to cross federal lands in the Trans-Alaska Pipeline System (TAPS) Corridor for the construction, operation and termination of one natural gas pipeline and related facilities from Prudhoe Bay to Anderson Bay at Valdez. The document is attached as Appendix G-6.

State of Alaska Conditional ROW Lease (December 10, 1988). A State of Alaska Conditional ROW Lease was issued to YPC on December 10, 1988. That ROW lease contains the text and stipulations of the Final ROW Lease that become effective when the Conditional ROW Lease requirements are met. It addresses the pipeline on state lands from the North Slope to Anderson Bay, within the TAPS corridor, in a manner consistent with the federal ROW grant. The document is attached as Appendix G-7.

TAGS Project-wide Final EIS. YPC received a project wide FEIS in June of 1988 The EIS served as the National Environmental Policy Act ("**NEPA**") compliance document on which all federal agencies based their permit application decisions. In it the agencies adopted a unique "tiered" permitting process. The document is attached as Appendix G-4.

FERC Anderson Bay Final EIS (March 1995). YPC having fulfilled NEPA administrative review requirements, allowed FERC to issue place of export authorization. The document is attached as Appendix G-11.

9.6 Federal Loan Guarantee and Debt Financing

The Port Authority will take advantage of any available indirect or direct government financing. As risk mitigation, however, the Port Authority has not included any such government assisted financing in its modeling or Project estimates.

For starter, because the Project is an export project the Port Authority has not counted on qualifying for federal loan guarantees under the Alaska Natural Gas Pipeline Act of 2005, 15 U.S.C. § 721n (2006).

Potential options include tax-exempt financing under the Internal Revenue Code ("**IRC**"). The Internal Revenue Service ("**IRS**") has determined the Port Authority is a political subdivision of the State, meaning not only is its income exempt from federal income taxation it may issue tax-exempt bonds. However, as currently configured most of the Project may not qualify for Port Authority or State of Alaska tax-exempt financing under the rules governing private activity bonds. The Port Authority views conduit financing of portions of the Project via the Alaska Railroad Corporation's ("**ARRC**") ability, under IRC, 26 U.S.C. § 149(c)(2)(C)(ii) (2006), to issue tax-exempt bonds outside of the private activity limitations as in keeping with the broad transportation function contemplated by the Alaska Railroad Transfer Act, 45 U.S.C. § 1207 (2006). Consequently the Port Authority will work with the ARRC to identify portions of the Projects – such as the Pipeline, LNG facilities, or tankers - suitable for tax-exempt financing opportunities. This includes, to the extent deemed necessary by bound counsel, seeking an IRS letter ruling affirming the tax-exempt status of a future issuance.

The Port Authority also believes direct participation in financing of the Pipeline portion of the Project should be explored by the State (although again the Port Authority has not made such participation a condition of this Application) as a way to mitigate financing risks and costs.

In compliance with AS 43.90.130(10) the Port Authority commits to propose and support rates for parts of the Project the Port Authority owns, in whole or in part, that are based on a capital structure for rate-making that consists of not less than 70% debt.

However, rather than having one or more third party investors taking a small but high return equity stake in the pipeline to mitigate the risks, and thus costs, associated with one hundred percent debt financing, the Port Authority commits to exploring with the State the following alternatives (the below discussion is an option for further discussion but and not a formal proposal or requirement of the Application).

The State could provide all or part of the equity investment in the Pipeline, either directly or through the Port Authority, allowing it to become the immediate beneficiary of a high ROE. The State would also not be penalized on the reduced wellhead value of ANS gas caused by a higher cost of equity because, although a higher tariff would lower royalty and taxes, the State would be collecting the revenues that caused the wellhead value drop.

The State could take an equity stake in the Pipeline, but demand a ROE inline with FERC's traditional 14% rather than the higher return outside investors would require given the equity stakeholders will likely have to carry some overrun risk. By requiring a ROE below market rates, the Pipeline would have lower tariffs. Lower shipping costs would encourage ANS basin exploration and future gas development projects by lowering the costs associated with taking gas to market. Additionally, the State would make up some of the subsidy through increased well head values that would result in higher royalties and taxes.

The State could take a subordinated debt position. One hundred percent debt financing may not be practical under the Port Authority's base case. However, it might be feasible if the State took a 30% subordinated debt position. By the State holding the subordinated portion of the debt, and being at the bottom of the payment waterfall, the first 70% of the debt could be financed at rates similar to what would be experience if the Pipeline had 30% equity. The State could significantly reduce the cost of the last 30% of debt by accepting that subordinated debt position but not charging a premium for it. Alternatively, a private investor could take the subordinated debt position, but the State could guarantee the investor would be paid back.

9.7 Certificate Authority from the Applicable Jurisdictional Agencies

As discussed in detail in Section 4.9 above, in 1987 FERC issued an order in which it declined to exercise discretionary authority under section 3 of the NGA to regulate the siting, construction, and operation of the pipeline component of the Project. FERC concluded that, in the case of exports of gas, unlike imports, ratepayers would bear no economic consequences of the pipeline. FERC further noted that the costs of the pipeline would be borne by the project owners, lenders, investors, and foreign gas purchasers.[26] DOE subsequently concurred with FERC's determinations.

The Port Authority intends to pursue this issue with FERC and DOE to affirm that the FERC regulators intend to stay this course. However, in the event that FERC and DOE reverse their position and FERC exercises jurisdiction over the Pipeline's rates and terms and conditions of service, that jurisdiction would necessarily have to attach under FERC's jurisdiction under section 3 of the NGA to regulate aspects of the LNG liquefaction terminal at Valdez. That is the same authorization that will be required for the LNG liquefaction terminal at Valdez. As currently conceived, none of the gas leaving Valdez will be shipped to the United States and, therefore, the Port Authority views a change in position as unlikely. However, if that plan changes in the future, the scope of FERC's jurisdiction over the pipeline could change as well.

[26] See Yukon Pacific Corporation, 39 FERC ¶61,216 (1987).

10. Financial Plan

10.1 Description of Applicant and Participating Entities

The Port Authority is described in Sections 2.1 and 2.2. A number of world class energy companies have provided various degrees of written commitments to participate with the Port Authority. Additionally, it is the intention of the Port Authority to work with Alaska Native Corporations in areas of the Project that are available and appropriate. Initial meetings toward that end have proved to be very positive.

10.2 Demonstration of Financial Resources and Financing Plan Approach

Upon License award, the Port Authority will negotiate and conclude participation agreements with prospective strategic partners that have expressed an interest in the Project. These strategic partners will provide development funding to implement the Project up through the final investment date.

At present, the Port Authority envisions the implementation of a limited recourse project financing to raise debt for the Project which would complement the equity commitments and other financial undertakings to be provided by the strategic partners. The Port Authority has included a copy of its confidential financial model with this Application..

11. Performance History and Project Capability

AS 43.90.130(2) requires an applicant to demonstrate the readiness, financial resources, and technical ability to perform the activities specified in the Application by describing the applicant's history of compliance with safety, health and environmental requirements, the ability to follow detailed work plan and timeline, and the ability to operate within an associated budget.

The Port Authority was formed in 1999 as a municipal port authority under State law by the City of Valdez, the Fairbanks North Star Borough and the North Slope Borough. It is a single purpose entity created to build or cause to be built a natural gas pipeline from Prudhoe Bay to Valdez. It consequently does not have an operational history, including a history of compliance with safety, health and environmental requirements, following detailed work plans and timelines, and operating within an associated budget.

Rather from the beginning of its formation, the Port Authority has enlisted the participation of world leaders in the development of large-scale oil and gas projects for expert advice in the areas of: engineering and design, cost estimation, economic modeling, LNG shipping, and LNG and NGL marketing. It is thus through strategic partnering that the Port Authority will have the readiness, financial resources, and technical ability to perform the activities specified in this Application. The Port Authority will function much like the other 160 port authorities across the country and contract with qualified, industry recognized companies to perform the various functions necessary for the construction, operation and maintenance of the Project.

12. Project Economic Viability

This section provides an analysis of the economic viability of the Project, as specified in RFA section 2.10.1. The analysis is organized as follows:

- Section 12.1 describes the targeted primary markets for LNG and NGL.
- Section 12.2 describes the estimated Project costs and projected rates and third party fees for transportation, liquefaction, and processing services for the Project's components.
- Section 12.3 provides a projection of wellhead netback revenues to the North Slope producers, based on: (a) the estimated gross revenues from gas and NGL sales in the target markets; less (b) estimated costs of transportation and processing.
- Section 12.4 provides a projection of cash flows to the State of Alaska and the U.S. federal government, based on projected government revenues from taxes and royalties.
- Section 12.5 provides an analysis of the competitive position of the Project relative to proposed other Alaska gas transportation projects.

12.1 Target Markets for LNG and NGL

The Port Authority has designed its project with the assumption that LNG and NGL produced at the liquefaction and liquids extraction facilities in Valdez will be transported from Valdez to markets in the Pacific Basin that are most attractive to the sellers of gas in terms of market price and depth and liquidity of such markets.

At present, markets in East Asia, specifically Japan, Korea and Taiwan, appear to be the most attractive in the Pacific Basin in terms of both prices and market depth. Therefore, the economic viability analysis in this section 12 of the Application is based on the assumption that natural gas liquefied at the facility in Valdez will be transported to and sold to consumers in East Asia.

The Port Authority has been approached by experienced gas marketing companies, who have expressed interest in purchasing LNG and NGL on a free-on-board ("**FOB**") basis in Valdez and anticipate to market such LNG and NGL to consumers in East Asia, as these markets appear to be the most attractive based on current market conditions.

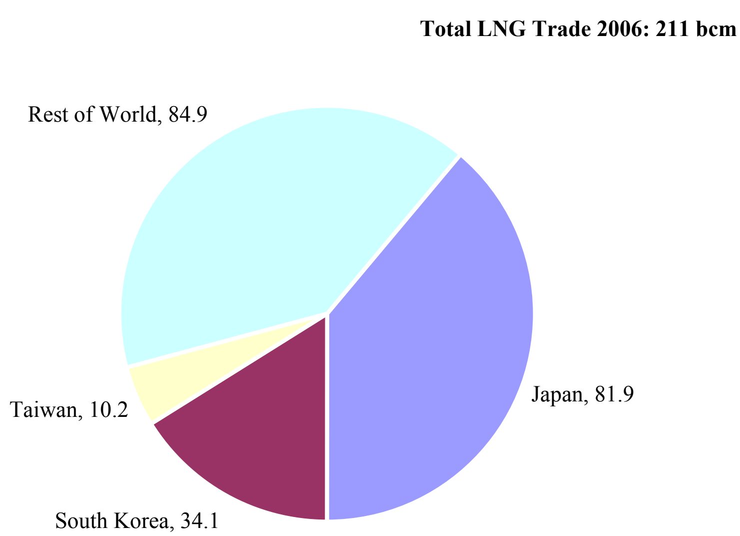
The Port Authority has designed the commercial structure of its Project to maintain the flexibility to offer transportation and liquefaction services to third party shippers (including North Slope producers of natural gas) who may desire to maintain ownership and marketing control of the LNG and NGL produced at Valdez. In such a scenario, the Port Authority and its [Project Partners] will not have control over the ultimate destination of the LNG and NGL and the responsibility for selection of destination markets, transportation and marketing will belong to such third party shippers of natural gas. However, for the purposes of the analysis in this Section 12, it has been assumed that such third party shippers would seek to maximize sales prices and netback profits and, therefore, would seek to market their LNG and NGL in the most attractive markets available to them, which, based on current market conditions, would imply LNG and NGL markets in East Asia.

The sections below provide an in-depth description of the characteristics of the LNG markets in East Asia, including projected supply and demand, price-setting mechanisms, and projected market prices.

12.1.1 East Asian LNG Markets: Demand and Supply

The East Asian market for LNG, comprising Japan, South Korea and Taiwan, has been the largest regional market for decades. In 2006, the total amount of LNG traded internationally was the equivalent of 211 billion cubic meters ("**bcm**") of natural gas,[27] approximately equal to 154 mmta of LNG. Of this total, the combined LNG imports Japan, Korea, as shown in Figure 9 below, represented 60% of total LNG trade in 2006.[28]

Figure 9 Global LNG Imports 2006 (bcm)



Source: BP Statistical Review of World Energy June 2007.

Japan is the single largest country importer of LNG in the world. As shown in Figure 9 above, Japan imported 81.9 bcm of LNG in 2006 (or approximately 60 mmta of LNG), accounting for 39% of global LNG imports for the year.[29] South Korea is the second largest country importer of LNG, with approximately 16% of worldwide imports. Taiwan accounts for approximately 5% of world LNG imports.

[27] BP Statistical Review of World Energy June 2007.

[28] Id.

[29] Id.

In addition to the established East Asian LNG importers of Japan, South Korea and Taiwan, China has recently begun importing relatively small amounts of LNG. While China is expected to grow as an LNG buyer, the level of Chinese demand in the future is uncertain. China has not been included as a base case target market for LNG in this analysis.

Global demand for LNG market is projected to grow substantially over the next 25 years. The forecast global demand growth for 2010 is between 198 mmta and 227 mmta in 2010, for an increase of 29-47% over 2006 levels.[30] Demand in 2020 is projected to grow to 350-376 mmta by 2020 and to 379-509 mmta by 2030, or an increase to roughly three times the current size of the market.

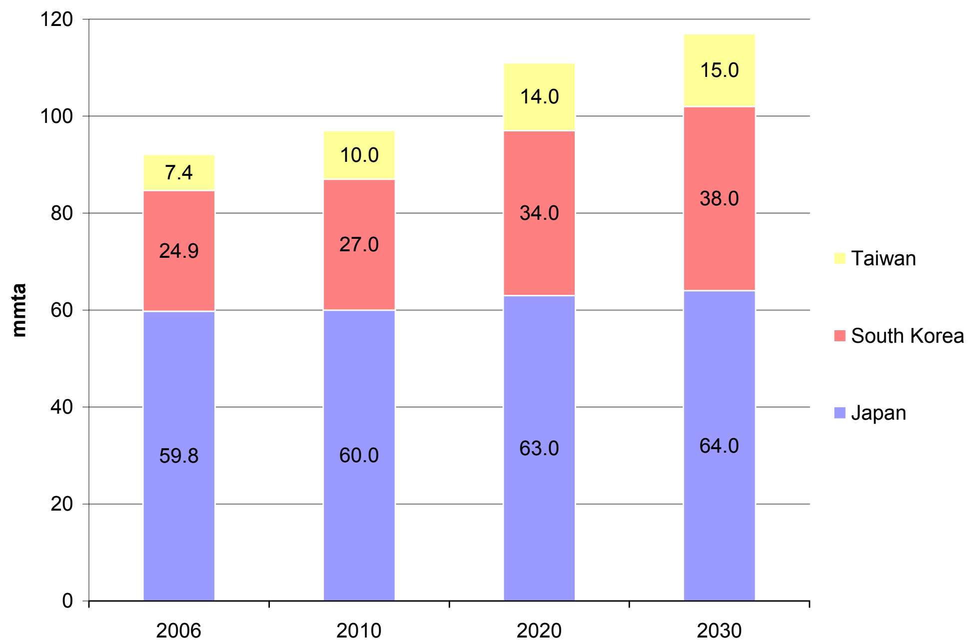
While LNG demand in the Atlantic basin is expected to grow rapidly, particularly as the U.S. continues to import a significant portion of its natural gas consumption in the form of LNG, demand growth in the Pacific basin is also projected to grow substantially.

Based on projections from the Institute of Energy Economics, Japan ("**IEEJ**"), the combined demand for LNG from the three major current markets, Japan, South Korea and Taiwan is forecast to grow from a 2006 level of 92 mmta in 2006 to between 111 mmta and 129 mmta by 2020 under IEEJ's "low growth" and "high growth" forecast scenarios, respectively.

Figure 10 below shows forecast demand from the three countries for 2010, 2020 and 2030 under the "low growth" scenario. Figure 11 shows forecast demand for the same time frame under the "high growth scenario.

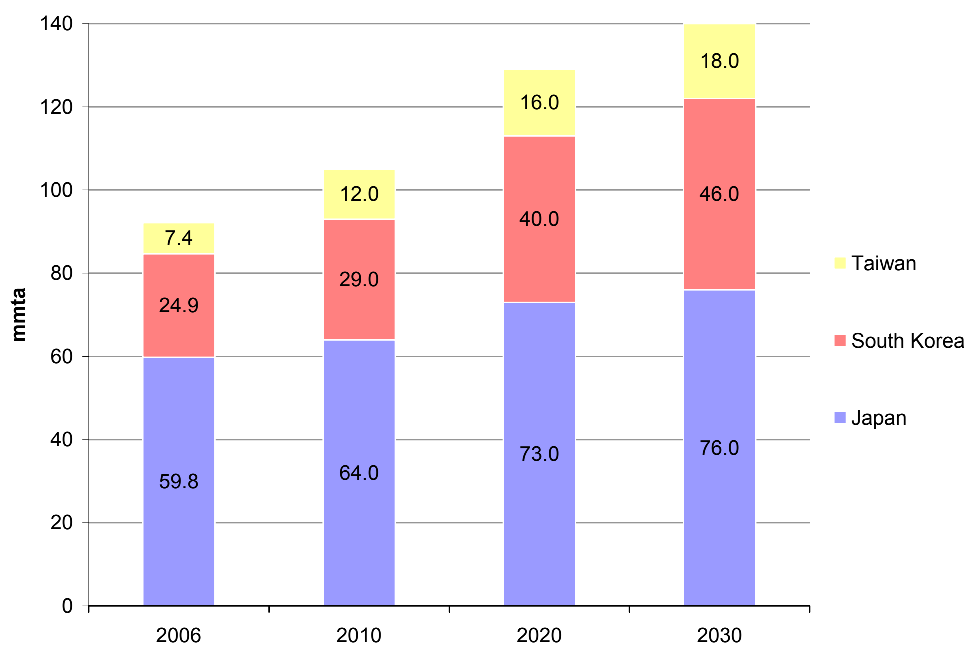
[30] Source: The Institute of Energy Economics, Japan. "Natural Gas and LNG Supply/Demand Trends in Asia Pacific and Atlantic Markets (2006), September 2007.

Figure 10 LNG Demand Growth in East Asia (Low Growth Scenario)



Sources: IEEJ for forecast 2010 – 2030; BP Statistical Review of World Energy June 2007 for 2006 figures.

Figure 11 LNG Demand Growth in East Asia (High Growth Scenario)



Sources: IEEJ for forecast 2010 – 2030; BP Statistical Review of World Energy June 2007 for 2006 figures.

In addition to growing demand from the three established LNG importers in East Asia, China is projected to emerge as a major importer of LNG. LNG demand in China is forecast to increase from less than 1 mmta currently to 10-16 mmta by 2020 and 20-33 mmta by 2030. Due to the uncertainty associated with the development of China as a major LNG importing country, it has not been included as a base case destination market for the Project at this time.

Another development of potential significance in the Pacific basin LNG market is the forecast increase in demand for LNG from India, which would open additional supply opportunities for both Pacific and Middle Eastern suppliers of LNG.

The Pacific basin LNG market has also been affected by the decline of LNG exports from Indonesia's Arun and Bontang liquefaction plants due to steadily dwindling production from aging gas fields, coupled with increased diversion of gas production to satisfy local demand.

12.1.2 Price-Setting Mechanisms in the East Asian LNG Markets

Long-Term Contracts and Price Setting

Traditionally, most LNG traded in the East Asian market has been purchased on a bilateral basis under long-term contracts extending over twenty or more years. Although the general characteristics of the pricing provisions in these contracts are known, most LNG sales and purchase agreements are generally treated as confidential commercial arrangements, with the details of specific pricing and other provisions typically not available to the public.

At each point in time, East Asian buyers are purchasing LNG under a multitude of different long-term supply contracts, each of them executed under specific market conditions at the time of the agreement between the individual buyer and supplier. As market conditions change over time and the individual circumstances of specific buyers and sellers vary, it would not be unusual, at a given point in time, for buyers to be purchasing LNG under different contractual prices.

The characteristics of the East Asian LNG market described above mean that typically there is no single "market price" of LNG in the East Asian market but, rather, a potentially a number of different active supply contracts with varying price provisions. This is different than the situation in the North American natural gas marketplace, where the price discovery mechanism is more transparent and is dominated by a spot market at various regional gas trading hubs.

For the purposes of the analysis in this Application, the projection of East Asian market prices for LNG is assumed to mean the contractual terms that the project would be expected to enter into on a long-term basis with East Asian buyers of LNG, on the basis of observed current market conditions and recent transactions between suppliers and buyers in Pacific Basin.

Oil-Indexation in Price Formulas

Customarily, LNG sales and purchase contracts with East Asian buyers have included price-indexation provisions that directly link the price of LNG to oil prices. Due to the importance of Japan as the largest buyer the LNG market, price formulas in contracts with South Korea or Taiwanese buyers have tended to follow the model established in Japanese LNG contracts by establishing the price of LNG as a function of the Japan Crude Cocktail price ("**JCC**") of a basket of crude oils imported into Japan.

Historically, the JCC-indexed price formulas used in Japanese supply contracts have had the following formulation:

$$P = A * JCC + B$$

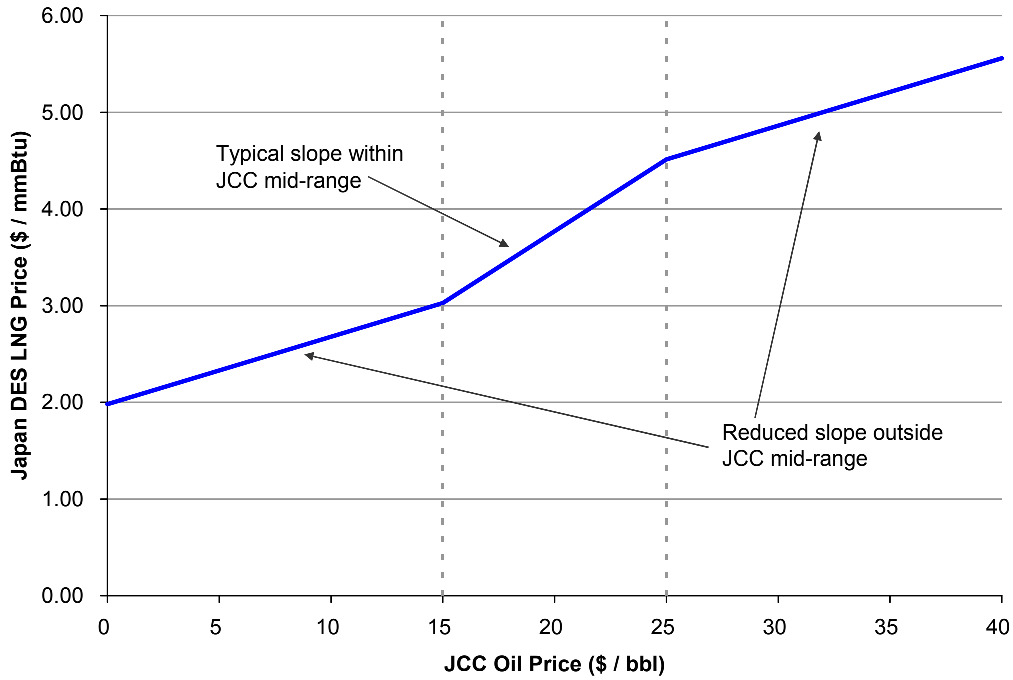
where:

P is the price of LNG (in cents per mmBtu) in Japan on a DES basis; the slope A is often 14.85 or similar; and the intercept B is a number between 70 and 90.

The basic formula above would apply in the mid-range of "expected" oil prices, which in the past (during periods of significantly lower oil prices) has been in the range between $15 and $25 per bbl. Outside of this range, the formulas have typically been modified applying the so-called "S-curve" which reduces the slope of the curve by about half. The intent behind this S-curve "flattening" of the slope is that for prices exceeding the band of expected long-term prices, the price relationship is changed such that in periods of very high oil prices the buyer benefits from reduced LNG prices in relative terms to oil, and in periods of very low prices the seller benefits from increased prices relative to oil.

Figure 12 below illustrates graphically the relationship between JCC oil prices and the LNG prices for supply to Japan on a DES basis that has been used in long term contracts in the past.

Figure 12 Historical Japan DES LNG "S-Curve" Formula



Source: Alaska Gasline Port Authority Financial Model

In recent years, market developments have put an upwards pressure on the historical LNG formula. Suppliers have been in a favorable position since 2005, as the Pacific basin market has moved to a position of expected supply shortages,[31] which has been due to a number of factors, including growing demand and delays in several Pacific basin LNG projects in development.

This has resulted in pressure on buyers to revise the traditional LNG pricing formulas to achieve higher prices, including by reducing or eliminating the S-curve "flattening" of the price curves and increasing the slope in the formula.

Based on publicly available market reports, recent Australian Northwest Shelf supply arrangements have significantly increased sales prices by revising the slope in the formula upwards.[32] More recently, Kogas, the South Korean natural gas utility, has reportedly agreed to purchase LNG from Qatar using an even more seller-friendly price formula, based on a price relationship between crude oil and LNG close to thermal value parity.[33]

[31] See, for example, "S Korea faces LNG shortage of up to 4 mil mt/yr during 2007-2012," Platts Energy Bulletin, Oct 18, 2006.

[32] See, for example, *http://www.fgenergy.com/AOGC-2007.pdf* and h*ttp://www.oilsearch.com/resource/ 2007%20Investor%20Field%20Trip%20-%20%20GAS.pdf*

[33] Id.

These new pricing arrangements, under recent high oil prices, result in LNG prices that are significantly higher than what the LNG prices would have been using the traditional Japan DES S-curve formulas. For the purposes of the analysis in this Application, it has been assumed that the very strong position of sellers in the Pacific basin would not be sustained in the longer term, resulting in a somewhat eased the pressure on LNG buyers in the region. LNG prices are assumed to be 80 percent of JCC.

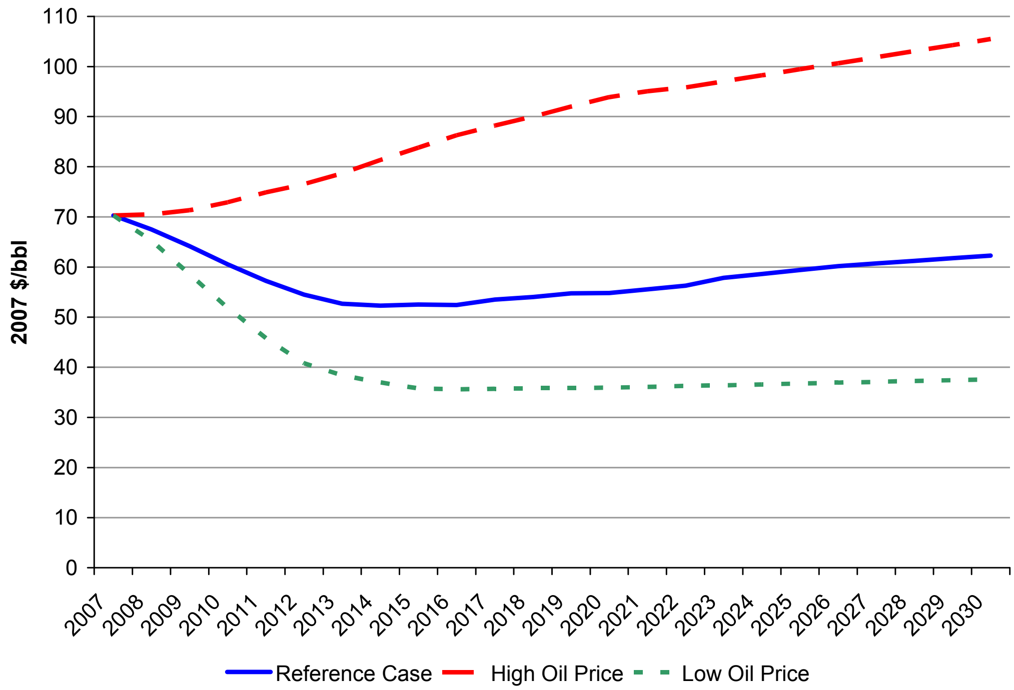
12.1.3 LNG Price Assumptions

The assumed contractual LNG price formula described in the preceding section establishes the relationship between oil prices and the LNG sales prices. The actual assumption for LNG prices used analysis in this Application is determined by the assumption for oil prices.

The RFA specifies that the assumed oil price in the Application is to be benchmarked off the price forecast for imported crude oil in the DOE's Energy Information Administration ("**EIA**") most recent Annual Energy Outlook publication. EIA provides oil and natural gas price forecasts for three price levels: (1) reference case; (2) high prices; and (3) low prices. EIA provides its forecast in constant 2005 dollars. For the purpose of consistency across the analysis in this Application, an inflation adjustment has been applied to the EIA price forecasts to express such prices in 2007 terms.

Figure 13 below shows the EIA price forecast at each of the three price levels, as provided in the EIA Annual Energy Outlook 2007 and adjusted for inflation from 2005 to 2007. Tables showing the specific price assumptions for each year are provided in **Error! Reference source not found.**.

Figure 13 EIA Price Forecast for Imported Crude Oil (2007 dollars)



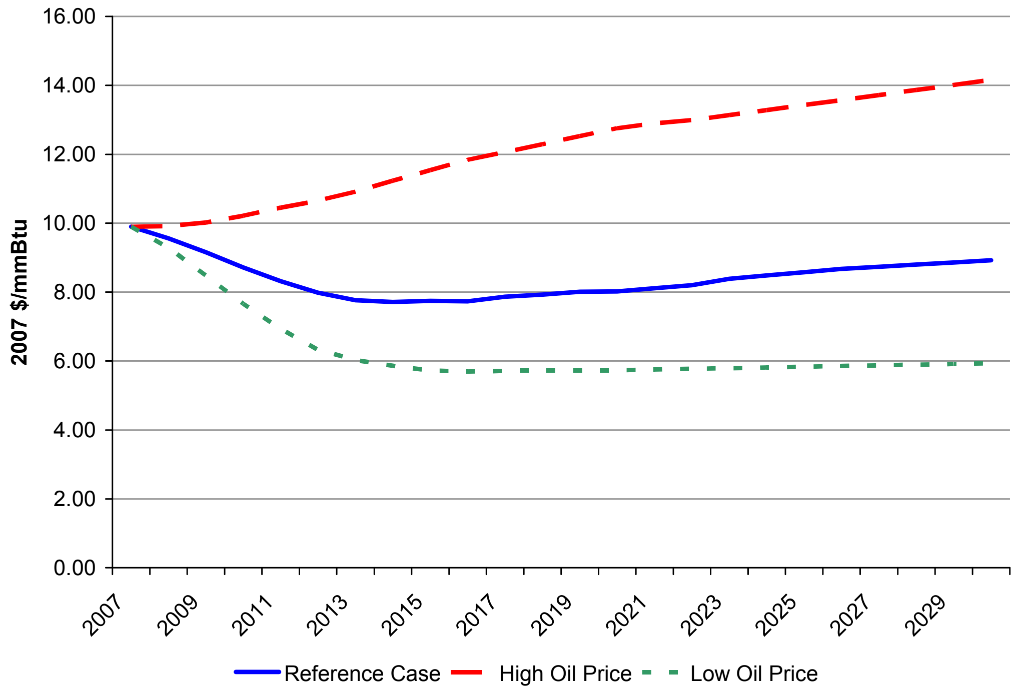
Source: EIA Annual Energy Outlook 2007

Based on the above three oil price scenarios and using the assumed formulaic relationship between the JCC oil price and East Asian LNG prices, as described in Section 12.1.2 and illustrated in **Error! Reference source not found.** above, a forecast of LNG sales prices has been prepared that corresponds to each of the three oil price scenarios (reference case, high price and low price) in EIA's Annual Energy Outlook 2007.[34]

Figure 14 below shows the assumed LNG prices in East Asia (on a DES basis), projected on the basis of EIA's oil price forecast that have been used for the purposes of the analysis in this application.

[34] The EIA forecast for crude oil prices is expressed as the forecast weighted average price of oil imported in the U.S. The formula for East Asian LNG prices, on the other hand, links the LNG price to JCC, which is based on a different basket of crudes than the weighted average U.S. import price. Given the very close correlation between the prices of different crude oils the EIA oil price forecast has been used as a proxy for JCC for the purposes of this analysis.

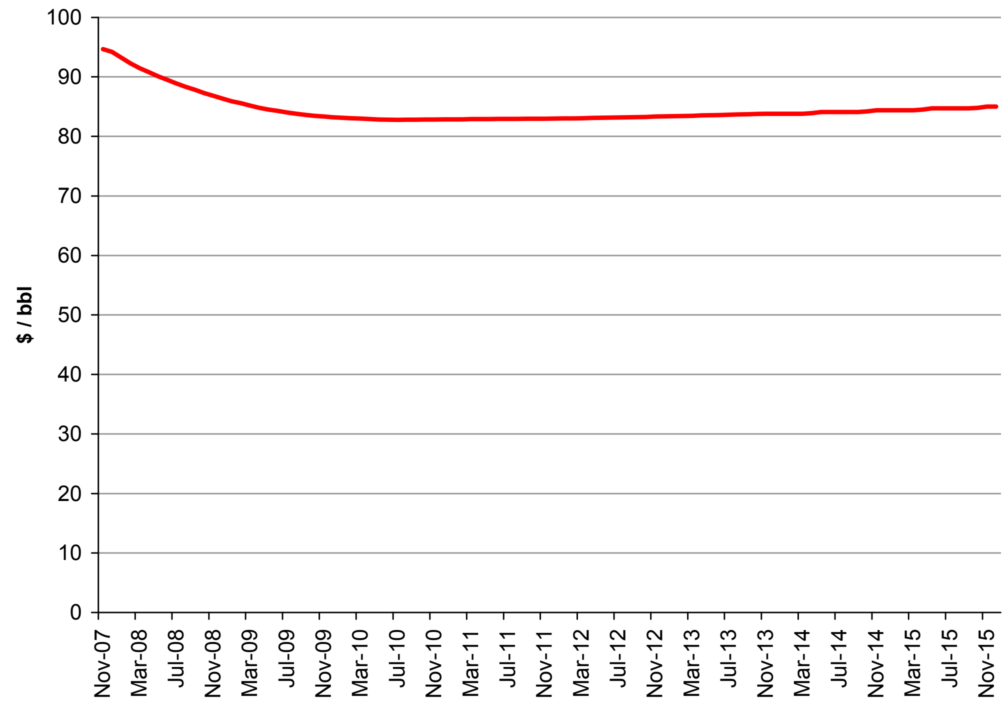
Figure 14 Assumed E. Asian LNG Prices (based on EIA oil price forecast)



Source: Alaska Gasline Port Authority Financial Model

The Base Case projections used in the economic viability analysis in this Application assume that oil prices correspond to the Reference Case forecast provided in EIA's Annual Energy Outlook 2007. However, EIA's High Oil Price scenario more closely resembles recently market oil prices. As shown in Figure 15 below, current oil futures prices on the New York Mercantile Exchange ("**NYMEX**") are between \$80 and \$90 per bbl for contract months through the end of 2015. This corresponds closely to the EIA High Oil Price scenario forecast for the same time period.

Figure 15 NYMEX Light Sweet Crude Futures (November 19, 2007)



Source: NYMEX

As described further in Section 12.1.4 below, in a high oil price environment, similar to the current market conditions, the East Asian LNG markets present a particularly attractive target markets for monetizing Alaska gas in comparison with alternative destination markets, including North American markets accessible via an overland pipeline. For this reason, the analysis presented herein provides results based on the High Oil Price scenario developed by EIA, in addition to the Base Case results that are based on EIA's Reference Case price scenario.

12.1.4 Comparison of E. Asian LNG Markets with N. American Gas Markets

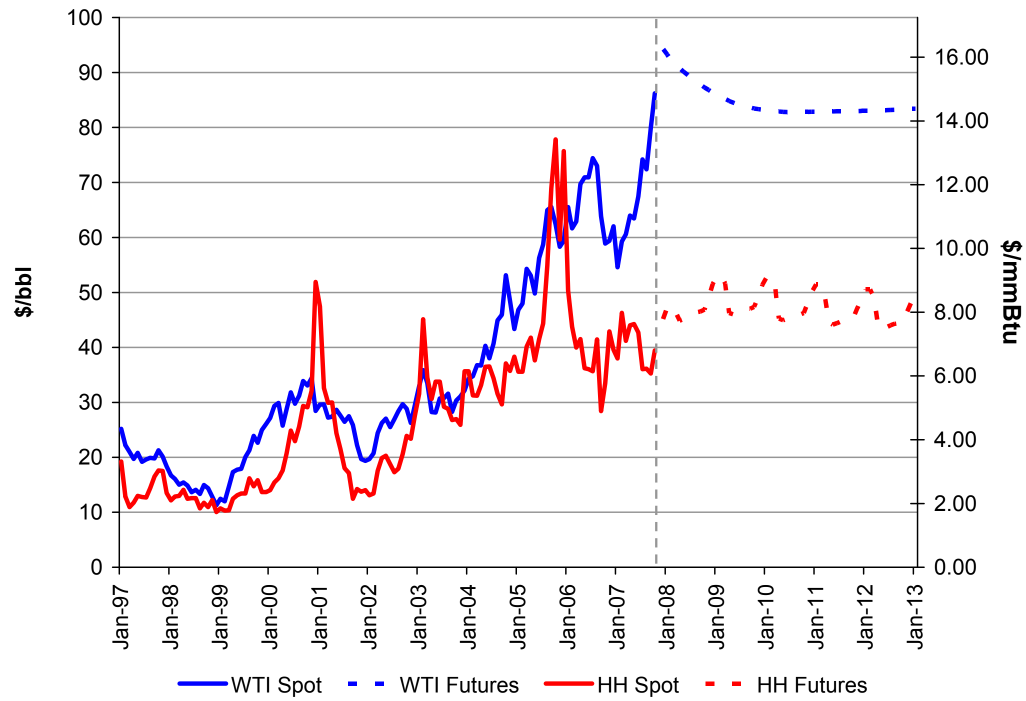
The direct contractual link between LNG prices and crude oil prices in the East Asian LNG markets contrasts with the price setting mechanism in North American gas markets, where gas prices are driven by supply and demand in localized but interconnected gas spot markets. Price formation in North America is the direct result of gas-on-gas competition. Oil prices do influence North American gas prices indirectly by having an effect on the supply and demand for natural gas. On the demand side, gas prices have often been constrained within a band defined by high-value and low-value petroleum products (distillate and residual fuel oil), due to the ability of some users to switch fuels. On the supply side, competition for exploration and production resources has prevented oil and gas prices from diverging significantly.

The historical relationship between North American oil and natural gas prices can be observed in Figure 16 below, showing Henry Hub spot prices and West Texas

Intermediate ("**WTI**") spot crude oil prices since 1997. The graph also shows recent NYMEX futures prices for months from December 2007 through January 2013.

The following key observations can be made from the graph: (a) although North American historical oil and gas prices have not been not tightly correlated, they have tended generally to move in tandem, with periods rising oil prices generally corresponding to periods of rising gas prices and *vice versa* for most of the last ten years; and (b) since roughly the middle of 2005, the price correlation appears to have weakened, with continuously rising oil prices not paired with correspondingly rising gas prices; and (c) the futures market prices natural gas for the next five years at levels substantially below futures oil prices (using a thermal equivalency factor of 5.8 mmBtu per barrel of oil).

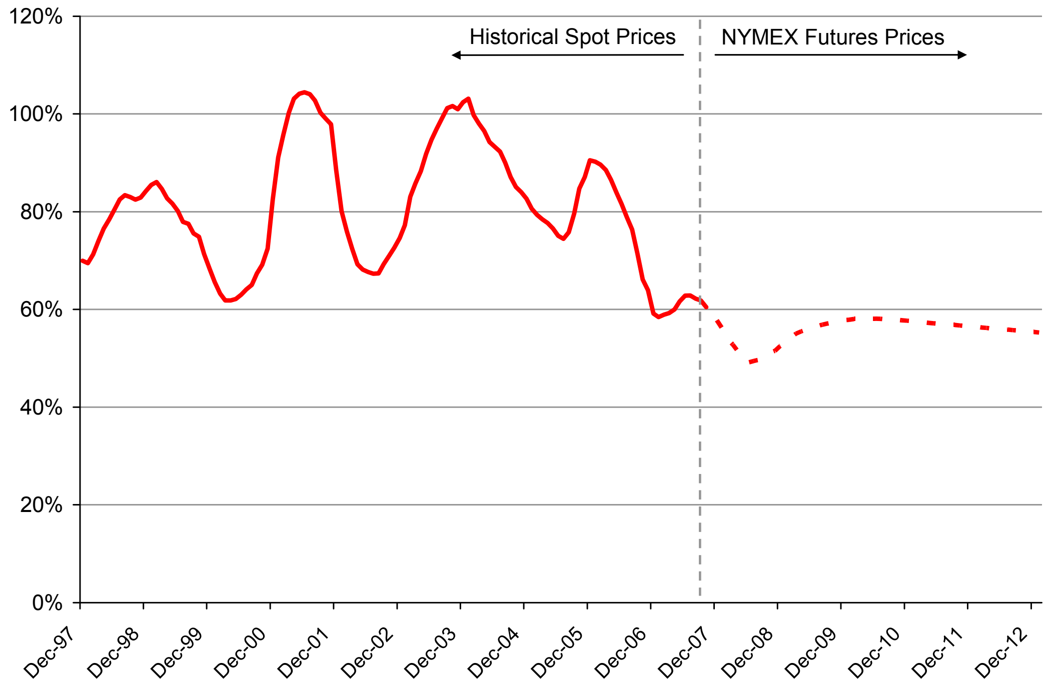
Figure 16 Historical Henry Hub and WTI Prices



Sources: Federal Reserve Bank of St. Louis Economic Research, http://research.stlouisfed.org/fred2/ *for historical spot prices; NYMEX for futures prices.*

The apparent recent "decoupling" of North American natural gas prices from continuously rising oil prices can also be illustrated by the graph in Figure 17 below, which expresses the Henry Hub prices as a percentage of oil prices, using a thermal equivalency factor of 5.8 mmBtu per barrel of oil). The relationship is shown both for historical spot prices and NYMEX futures prices. Prices are shown on a 12-month rolling average basis, to smooth out the effects of seasonal variations in natural gas prices.

Figure 17 Henry Hub Price as a Percentage of Oil Price



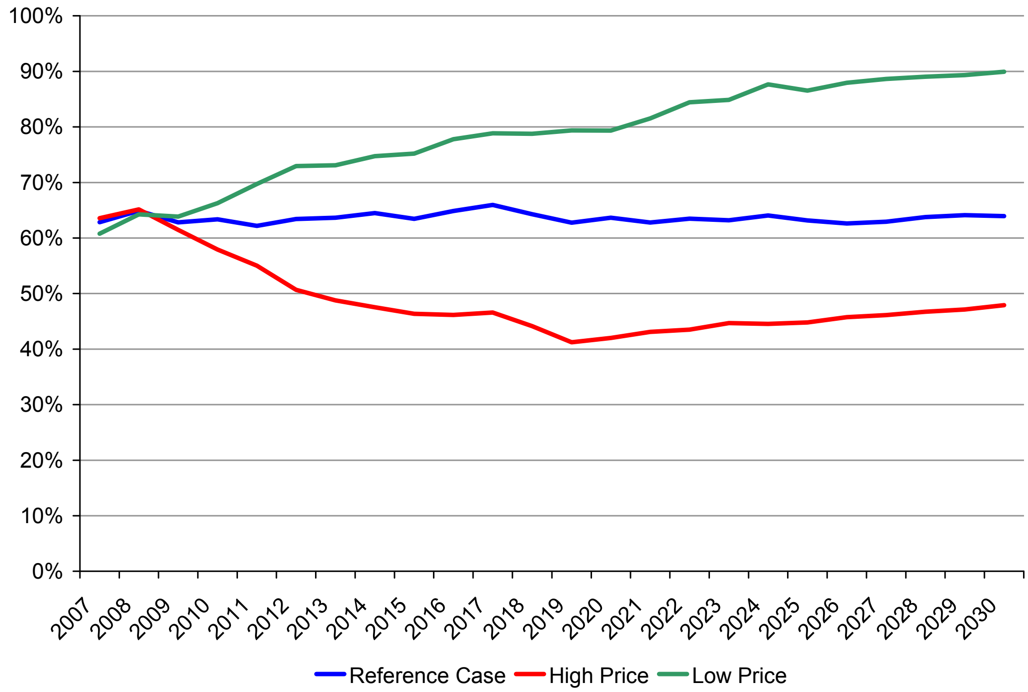
Sources: Federal Reserve Bank of St. Louis Economic Research, http://research.stlouisfed.org/fred2/ *for historical spot prices; NYMEX for futures prices.*

The graph above shows that historically Henry Hub spot prices have fluctuated within a band of roughly 60% and 100% of oil prices, with an average of approximately 80%. As oil prices have continued to climb during the last two years, Henry Hub prices have not increased correspondingly and have edged towards the 60% level in relative terms against oil. Prices on the NYMEX futures market indicate that Henry Hub gas prices are expected to remain below 60% of oil prices, indicating a lasting shift in the relative price relationship between oil and natural gas prices in North America, to the extent that the current high oil price environment persists.

The price forecasts in EIA's Annual Energy Outlook 2007 indicate a similar "decoupling" of the historical oil and gas price relationship in North America in the Reference Case and High Oil Price scenarios. As Figure 18 below illustrates, in the EIA Reference Case forecast, Henry Hub gas prices are projected to remain between 60% and 70% of oil prices, below the historical average during the last ten years.

In the case of EIA's High Oil Price scenario, Henry Hub gas prices and oil prices are forecast to diverge further from the historical relationship, with gas prices reduced to between 40% and 50% of oil prices, significantly below the historical levels. Only in the case of EIA's Low Oil Price scenario, gas prices are forecast to return to the historical level in relation to oil prices – with Henry Hub prices increasing from the current level of approximately 60% relative to oil up to 80-90% relative to oil for the period 2015-2030.

Figure 18 Henry Hub Price as Percentage of Oil Price (EIA forecast)

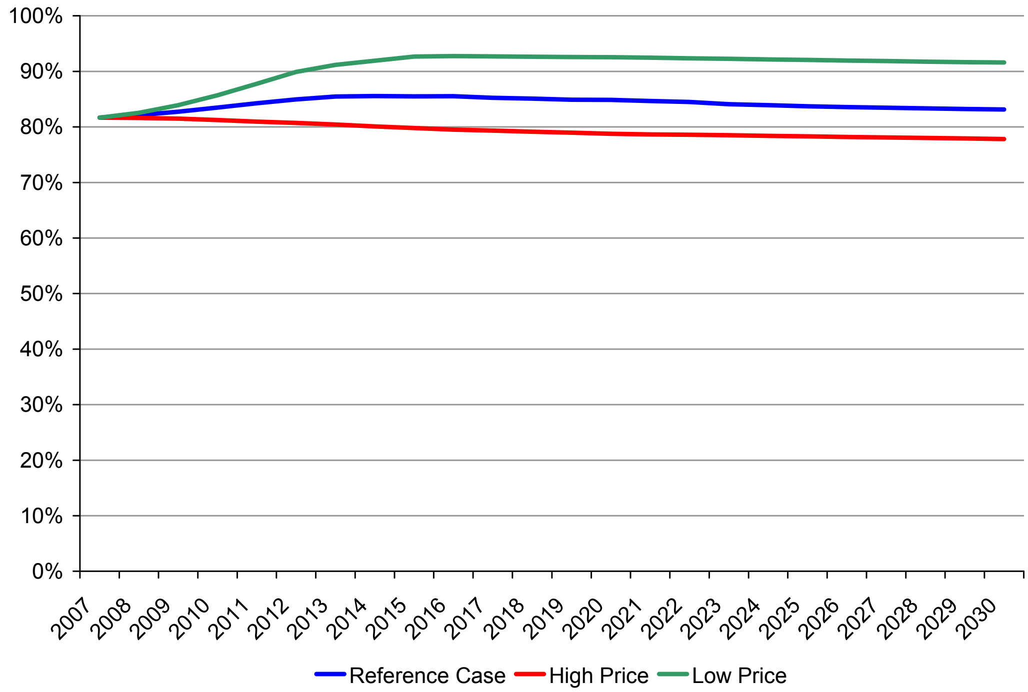


Source: EIA Annual Energy Outlook 2007.

In contrast to North American gas markets, the East Asian LNG markets would retain LNG prices that are relatively high in relation to oil prices, assuming that the JCC-indexation price formula provisions remain a central feature of Asian LNG purchase contracts. Figure 19 below shows projected East Asian LNG sales prices, expressed as a percentage of oil prices, under each of EIA's three oil price scenarios.

In all three cases, East Asian LNG prices are projected to remain at a consistently relatively high level relative to oil. Under the High Oil Price scenario, East Asian LNG prices are projected to remain at a level of approximately 80% percent of oil prices, which is significantly higher than projected Henry Hub gas prices of between 40% and 50% of oil under that scenario.

Figure 19 Forecast E. Asian LNG prices as Percentage of Oil Price



Sources: EIA Annual Energy Outlook 2007 for forecast oil prices; Alaska Gasline Port Authority Financial Model for forecast LNG prices.

The differences in projected responses of the North American gas prices and East Asian LNG prices to different levels of oil prices show that Asian LNG prices are forecast to remain relatively higher than North American prices under EIA's Reference Case scenario. Under the High Oil Price scenario, East Asian LNG prices are forecast to be significantly more attractive from a seller's perspective than North American gas prices.

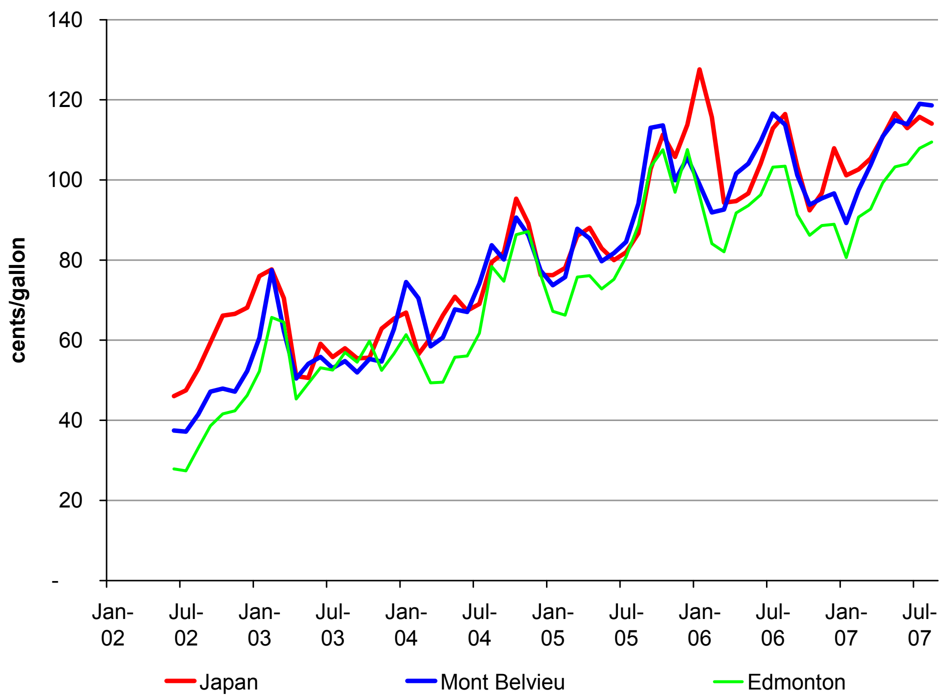
An additional advantage of the Asian LNG market is that in a high oil price environment, demand for LNG increases. Due to the features of the price indexation formulas in Asian LNG sales and purchase contracts discussed in Section 12.1.2 above, at high oil price levels LNG becomes relatively cheaper than competing oil products because most JCC indexation formulas have a slope of less thermal parity with oil.

The LNG project proposed by the Port Authority would place Alaska in a unique position to benefit from the advantages of the East Asian markets over alternative gas destination markets. Access to these LNG markets will be especially attractive for Alaska and its gas producers if the current high oil price environment persists.

12.1.5 Target LPG Markets

Like LNG, the Port Authority will retain destination flexibility with LPGs, thus being able to experience significant Project economics uplift by taking Project LPGs to the most desirable markets. Historically, LPGs in Asia have typically traded at a premium to North American markets, as indicated in Figure 20.

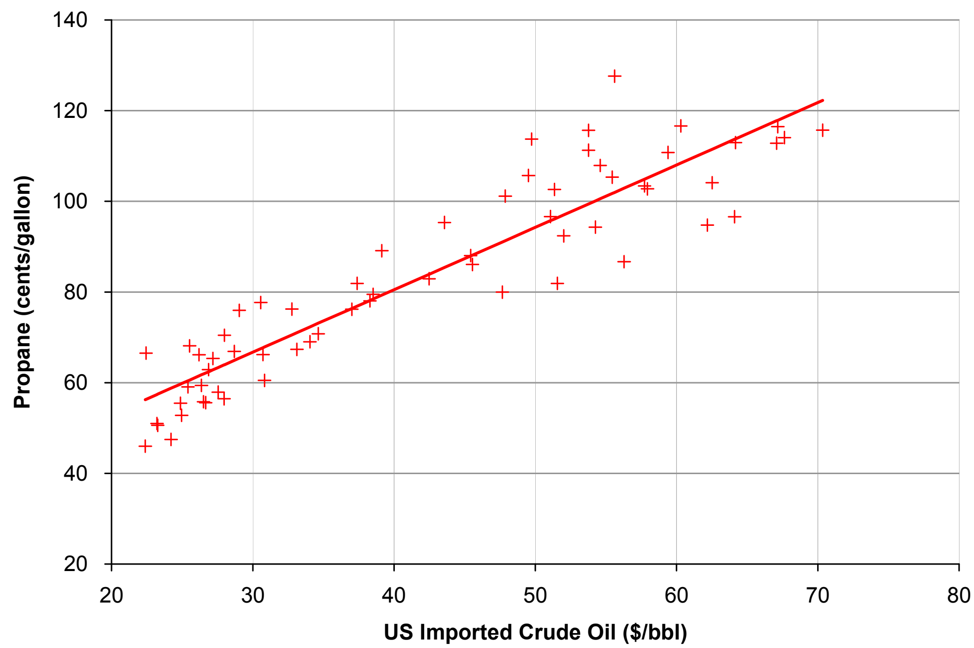
Figure 20 Historical Propane Prices



The bases for LPG price forecasts are the Imported Crude Oil and Henry Hub price series in the EIA Annual Energy Outlook. Historical values for these prices were compared to prices between June 2002 and August 2007 for propane in Japan, Mont Belvieu, and Edmonton, to determine appropriate forecast relationships.

Propane prices in Japan are forecast based on Imported Crude Oil prices alone. In the historical period analyzed, this linear fit has an R-square statistic of 0.85 (Figure 21). Including Henry Hub prices in the fit slightly reduces the overall residuals between historical data and the regression. However, for more than half of the data points, the residual at that point is increased by including the Henry Hub fit. Furthermore, any fundamental link between Henry Hub and Japanese propane prices is tenuous. Therefore, Japanese propane pricing is not assumed to correlate with Henry Hub in the forecast period.

Figure 21 Relationship Between Japan Propane and US Imported Crude Oil



Propane prices at Mont Belvieu and Edmonton are both forecast based on a combination of Imported Crude Oil and Henry Hub prices. These multi-variable correlations have R-square statistics greater than 0.91 for the historical data. Figure 22 and Figure 23 show historical propane prices, prices from the correlation with Imported Crude Oil and Henry Hub, and the residuals between the historical and correlated prices.

Figure 22 Historical Mont Belvieu Propane and Correlation

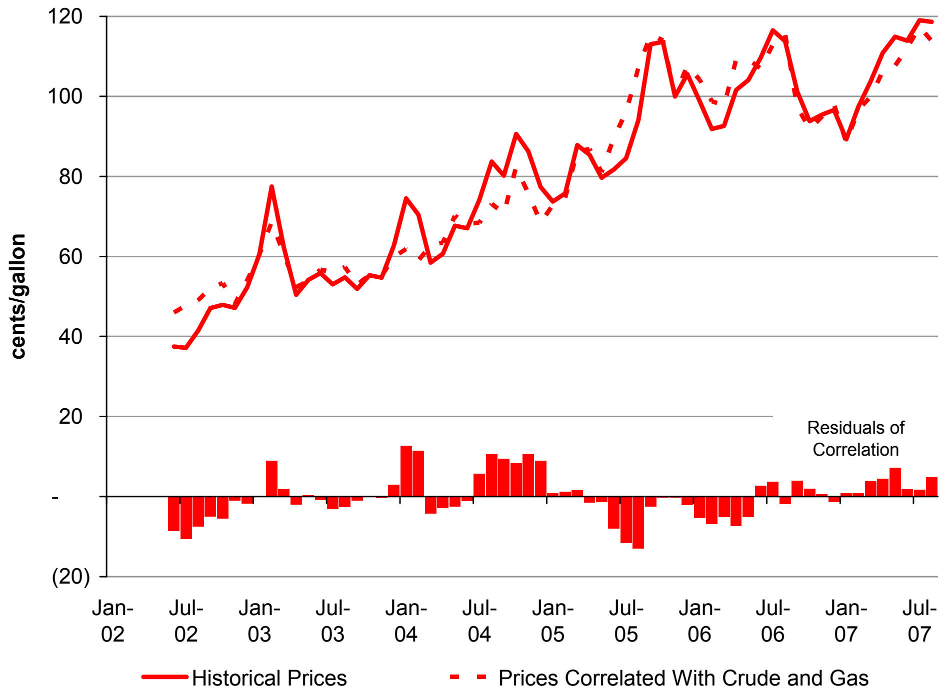
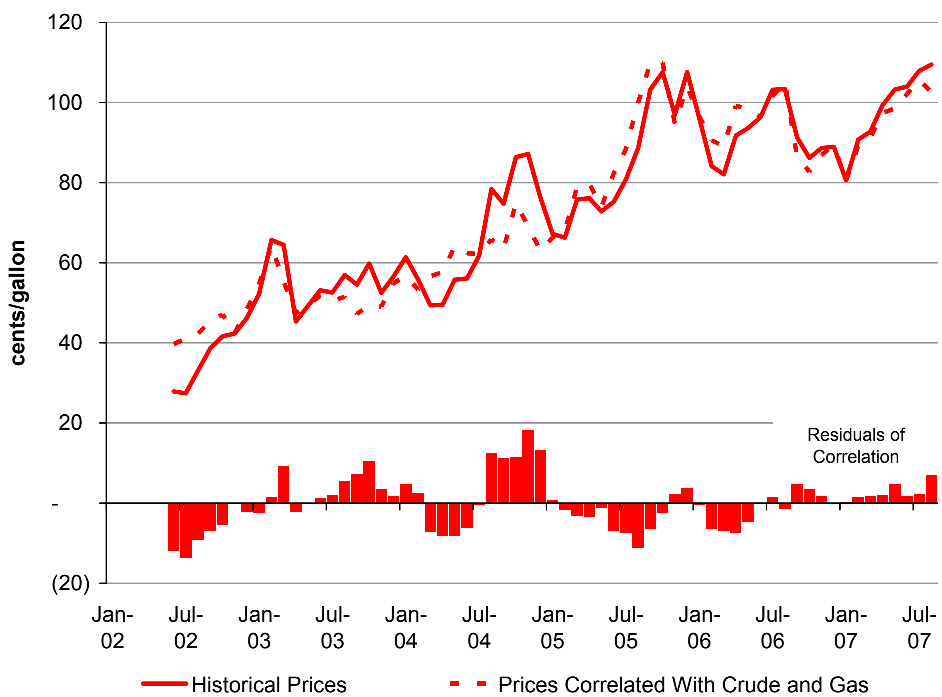


Figure 23 Historical Edmonton Propane and Correlation



12.2 Project Costs

[*section pending*]

12.3 Netback Prices and Revenue

[*section pending*]

12.4 Cash Flows to the State of Alaska

[*section pending*]

12.5 Competitive Analysis

In addition to those identified elsewhere in the Application, the Port Authority has the following competitive advantages:

- 800 mile pipeline is 100% adjacent to TAPS, 100% in Alaska;
- Infrastructure in place for entire line – roads, bridges, camp pads, etc.;
- LNG project: lower overall cost and overrun risk;
- Liquefaction facilities utilize proven technology and well-tested design, resulting in a relatively low level of uncertainty in cost estimate;
- Low level of cost uncertainty for LNG marine transportation and regasification;
- Pipeline component has the highest capital cost uncertainty – for LNG project the Pipeline is only a portion of overall cost to market.

13. Project Technical Viability

For access to technical data related to the Port Authority's Application, please refer to Section 7.2.

14. Proposed Reimbursement

Pursuant to AS 43.90.130(9) the Port Authority proposes a 100% rate reimbursement, in a total amount not to exceed $500,000,000, under AS 43.90.110(a)(1)(A) and (B) to be specified in the License.

15. Former Point Thomson Unit

The Port Authority views commitment of natural gas from the former Point Thomson Unit ("**Point Thomson**") as critical to the success of any midstream project to monetize ANS gas. As discussed in Sections 4.3.1 and 9, however, the Port Authority is of the opinion that the current status of Point Thomson, decreases, rather than increases, Project risks associated with securing FT commitments.

The Port Authority's long held belief that Point Thomson gas is critical to success of it Project efforts has resulted in it being at the forefront of encouraging, and ultimately demanding, development of the field's resources.

In 2004 and the first half of 2005, the Port Authority repeatedly approached the Point Thomson working interest owners, seeking to discuss and negotiate transportation arrangements for gas from the field. It eventually became clear that the former leaseholders were not willing to discuss committing gas to an independent project.

In the fall of 2005, the Port Authority filed extensive factual and legal briefing to DNR, demanding that the State terminate the unit and reclaim the acreage for re-leasing to upstream producers interested in bringing Point Thomson gas resources to market. Since that time, the Port Authority has continued to assist DNR in its efforts to clear title on Point Thomson, including actively participating in the administrate and superior court unit termination proceedings.

The Port Authority's close association with the termination process has left it confident that DNR's efforts will be successful, meaning the State could be in the position to begin the re-leasing process as soon as 2009. Because the Point Thomson reservoirs are largely delineated, and there is little exploration risk associated with the acreage, interest in re-leasing by upstream producers is expected to be strong. Consequently, DNR will be in a position to demand and receive bid terms more favorable than those traditionally received by the State for exploration acreage.

To guarantee maximum ultimate hydrocarbon recovery from Point Thomson, the Port Authority recognizes that gas cycling may be required for a number of years before significant gas offtake from the field is appropriate. Thus the Port Authority commits to immediately begin working with DNR and the AOGCC to establish rules for Point Thomson gas offtake so that the timing of Point Thomson gas availability to the Project can be determined before the Project's initial open season. The Port Authority will also work with the State to embed express "date certain" development commitments into the new leasing arrangements to ensure: (a) cycling, if required by the AOGCC, occurs rapidly, possibly even before Project construction; and (b) Point Thomson gas shipments through the Project are coordinated to maximize recovery in light of Point Thomson and Prudhoe Bay reservoir needs (i.e., Point Thomson gas sales should occur such that total recovery is maximized from both units).

Additionally, the Port Authority believes DNR should take this opportunity to seek a substantially larger share of Point Thomson profits than it has received in the past under its traditional exploration lease arrangements. Structuring the lease sales with royalty or a net profit interest ("**NP**")[35] as one of the key bid variables can be expected to result in a high level of State "take." The Port Authority believes the original Northstar lease sales provide a good analogy for what the State might achieve with Point Thomson.

Northstar is a joint offshore State/federal oil and gas unit located to the north of the Prudhoe Bay unit. In 1979, the Northstar prospect was first put out for bid on a NP bid basis. Four State leases were bid in 1979,[36] and one in 1983,[37] with Amerada Hess and Shell as the primary leaseholders. The four 1979 leases gave the State a one-fifth royalty share plus an 89% NP. The 1983 lease gave the State a one-eighth royalty share plus a 40% NPI, for an average NP on the State's share of the unit of roughly 80%.

Total State "take" can be viewed as the amount of profits on oil and gas the State gets after it collects its royalty share, NP (if any), and severance, property, and state income taxes. For the Northstar leases in the 1980s this can be conservatively estimated at over 90%, assuming: (a) nominal severance taxes because of the later adopted Economic Limit Factor; (b) nominal property taxes (which are small in the total picture); (c) State income taxes of about 9% with an effective rate about half that after deductions; (d) a blended 19% royalty; and (e) a blended 80% NP.

A re-leasing of Point Thomson acreage would share many characteristics with the State Northstar lease sales, including a high oil price environment, but would be more attractive to the lessee because of the lack of exploration risk. Consequently, it is reasonable to assume the State will be able to achieve a similar 90% take for Point Thomson. According to a recent 2007 DOE study this is more than triple the 26.1% take (pre-PPT) Alaska would have historically expected ANS-wide after a major gas sale with West Coast oil at $60 per barrel.[38]

The same 2007 DOE study, assuming a flat price of $60 per barrel for ANS crude West Coast prices and ultimate Point Thomson recovery of 7.2 tcf of gas and 390 million barrels of condensates and oil, estimated that the State's total nominal take over the life of Point Thomson under the old lease terms would be approximately $24.3 billion, or a 26.9%.[39] If on re-leasing the State can achieve take percentages comparable to the Northstar leases, i.e., about 90%, the State would expect $81.0 billion over the life of the field given the same pricing, cost and ultimate recovery assumptions.

This figure is larger than DOE's estimated total $77.9 billion State take from all ANS production in the future if a major gas sale does not occur.[40] If a major gas sale does occur, DOE predicts total ANS State take under the old Point Thomson lease terms will

[35] A net profit interest can be simplistically represented as a share of total lease revenue minus the field development costs (including interest) and State royalty (Net Profit ≈ Gross Revenue – Field Costs – State Royalty). See 11 AAC 83.200-.228.

[36] ADL 312798, ADL 312799, ADL 312808, ADL 312809.

[37] ADL 355001.

[38] United States Department of Energy, *Alaska North Slope Oil and Gas - A Promising Future or an Area in Decline?,* Full Report 3-127 (August 2007).

[39] *Id*. at 3-139.

[40] *Id*. at 3-126.

equal approximately $153 billion,[41] meaning the additional $56.7 billion the State could bring in with a lease similar to the Northstar lease would increase State oil and gas revenues by about 37% over the life of the ANS.

Table 3 DOE Forecast of Economic Results for Point Thomson

Variable	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$4,639,810	$4,639,810	$4,639,810	$4,639,810
Total operating costs	$528,964	$528,964	$528,964	$528,964
State royalty	$3,912,862	$6,450,479	$10,256,900	$12,794,517
State taxes – Severance	$2,847,429	$4,630,958	$7,306,252	$9,089,781
State taxes – Income	$512,468	$936,974	$1,573,737	$1,998,244
State taxes – Other	$441,063	$441,063	$441,063	$441,063
State Total (Royalty & Taxes)	**$7,713,822**	**$12,459,474**	**$19,577,952**	**$24,323,605**
Federal taxes	**$5,980,620**	**$10,647,378**	**$17,647,510**	**$22,314,268**
Industry net income	**$11,653,704**	**$20,712,700**	**$34,301,198**	**$43,360,197**

Source: DOE

It can thus be seen that the magnitude of potential economic rents from Point Thomson are significant. If re-leased at anything approaching the NP shares originally received by the State in the Northstar leases, and combined with fixed development timelines, such terms will maximize the economic benefits to the State, while allowing Point Thomson gas, along with Prudhoe Bay gas, to provide the shipping commitments that will anchor the construction of an Alaska natural gas pipeline project.

[41] *Id*. at 3-141.

APPENDIX A

Application Checklist

Appendix A

Glossary of Selected Terms and Abbreviations

Glossary of Selected Defined Terms and Abbreviations

Term	**Definition**
AGIA	Alaska Gasline Inducement Act, AS 43.90.010 et seq.
ANGDA	Alaska Natural Gas Development Authority
ANGTA	Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. § 719 et seq.
ANS	Alaska North Slope
bcf/d	billion cubic feet per day
bcm	billion cubic meters
Bechtel	the Bechtel Corporation
BLM	U.S. Bureau of Land Management
DES	delivered ex-ship
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPC	engineering, procurement and construction
FEED	front end engineering design
FEIS	final environmental impact statement
FERC	Federal Energy Regulatory Commission
FNSB	Fairbanks North Star Borough
FOB	free-on-board
GCP	the proposed gas conditioning plant at Prudhoe Bay
GCP Participants	the entities that own and operate GCP
IEEJ	Institute of Energy Economics, Japan
JCC	Japan Crude Cocktail
License	the license awarded pursuant to AGIA
LNG	liquefied natural gas
LNG Facilities	the proposed liquefaction, and fractionation facilities, LNG and LPG storage, vessel loading and related facilities in Valdez
LPGs	liquid petroleum gases
m3	cubic meters
mbpd	million barrels per day
mmBtu	million British thermal units
mmta	million metric tons per annum
MOL	Mitsui O.S.K. Lines, Ltd.

MOL Companies	MOL and its subsidiaries BGT Limited and BLNG Inc.
NAESB	North American Energy Standards Board
NGA	the Natural Gas Act, 15 U.S.C. § 717 et seq.
NGLs	natural gas liquids
NPV	net present value
NSF	National Science Foundation
NTP	notice to proceed
NYMEX	New York Mercantile Exchange
Pipeline	the 806-mile overland natural gas pipeline extending from Prudhoe Bay to tidewater at Valdez proposed by the Port Authority
Port Authority	the Alaska Gasline Port Authority
Project	the project to develop, finance, construct and operate the Pipeline, LNG Facilities and GCP
RCA	Regulatory Commission of Alaska
RFA	Request for Applications
SIMP	stakeholder issues management plan
TAGS	Trans Alaska Gas System
TAPS	Trans-Alaska Oil Pipeline System
VLGCs	very large gas carriers
WTI	West Texas Intermediate
YPC	Yukon Pacific Corporation

APPENDIX A
APPLICATION CHECKLIST

	Statute	Requirement	RFA Reference	Applicant's Reference
	43.90.130(1)	Applicant must be filed by the deadline	1.6	N/A
	43.90.130(2)	Provide a thorough description of a proposed natural gas pipeline project for transporting natural gas from the North Slope to market, which description may include multiple design proposals, including different design proposals for pipe diameter, wall thickness, and transportation capacity, and which description shall include:	2.1	3.1 3.2 3.3 3.4 3.5.1 3.5.2 3.6
	(A)	The route proposed for the natural gas pipeline, which may not be the route described in AS 38.35.017(b);	2.1.1.	3.2.1
	(B)	The location of receipt and delivery points and the size and design capacity of the proposed natural gas pipeline at the proposed receipt and delivery points, except that this information is not required for in-state delivery points unless the application proposes specific in-state delivery points;	2.1.1	1.21 3.2.3
	(C)	An analysis of the project's economic and technical viability, including a description of all pipeline access and tariff terms the applicant plans to offer;	2.10. and 2.2.3.4.	12 – 12.1.5 13
	(D)	An economically and technically viable work plan, timeline, and associated budget for developing and performing the proposed project, including field work, environmental studies, design and engineering, implementing practices for controlling carbon emissions from natural gas systems as established by the United States Environmental Protection Agency, and complying with all applicable state, federal and international regulatory requirements that affect the proposed project, the applicant shall address the following;	2.2 to 2.8	4.1 4.2 4.3 4.9

	(D) (i)	If the proposed project involves a pipeline into or through Canada, a thorough description of the applicant's plan to obtain necessary rights-of-way and authorizations in Canada, a description of the transportation services to be provided and a description of rate-making methodologies the applicant will propose to the regulatory agencies, and an estimate of rates and charges for all services;	2.2.3.13 2.2.4.1 2.2.4.5	N/A
	(D) (ii)	If the proposed project involves marine transportation of liquefied natural gas, a description of the marine transportation services to be provided and a description of proposed rate-making methodologies; an estimate of rates and charges for all services by third parties; a detailed description of all proposed access and tariff terms for liquefaction services or, if third parties would perform liquefaction services, identification of the third parties and the terms applicable to the liquefaction services; a complete description of the marine segment of the project including the proposed ownership, control, and cost of liquefied natural gas tankers, the management of shipping services, liquefied natural gas export, destination, re-gasification facilities, and pipeline facilities needed for transport to market destinations, and the entity or entities that would be required to obtain necessary export permits and licenses or a certificate of public convenience and necessity from the Federal Energy Regulatory Commission for the transportation of liquefied natural gas in interstate commerce if United States markets are proposed; and all rights-of-way or authorizations required from a foreign country;	2.1.3 2.2.3.14	4.5 4.5.2 4.5.3 4.5.4 4.6 Appendix E Appendix L
	43.90.130(3)	If the proposed project is within the jurisdiction of FERC, does the Application commit:		

	(A)	Conclude, by a date certain that is not later than 36 months after the date the license is issued, a binding open season that is consistent with the requirements of 18 C.F.R. Part 157, Subpart B (Open Season for Alaska Natural Gas Transportation Projects) and 18 C.F.R. 157.30 – 157.39;	2.2 2.2.4.3 2.2.3	4.9.3
	(B)	Apply for Federal Energy Regulatory Commission approval to use the pre-filing procedures set out in 18 C.F.R. 157.21 by a date certain, and use those procedures before filing an application for a certificate of public convenience and necessity, except where the procedures are not required as a result of sec. 5 of the President's Decision issued under 15 U.S.C. 719 et seq. (Alaska Natural Gas Transportation Act of 1976); and	2.2 2.2.4.3	4.9.3
	(C)	Apply for a Federal Energy Regulatory Commission certificate of public convenience and necessity to authorize the construction and operation of the proposed project described in this section by a date certain;	2.2 2.2.4.3	4.9.3
	43.90.130(4)	If the proposed project is within the jurisdiction of the Regulatory Commission of Alaska, commit to		
	(A)	Conclude, by a date certain that is not later than 36 months after the date the license is issued, a binding open season that is consistent with the requirements of AS 42.06;	2.2 2.2.4.4	4.9.4 6.1.1
	(B)	Apply for a certificate of public convenience and necessity to authorize the construction and operation of the proposed project by a date certain;	2.2 2.2.4.4	4.9.4
	43.90.130(5)	Commit that after the first binding open season, the applicant will assess the market demand for additional pipeline capacity at least every two years through public nonbinding solicitations or similar means;	2.4 2.4.1.1	6.1.1
	43.90.130(6)	Commit to expand the proposed project in reasonable engineering increments	2.4 2.4.1.2	6.1.2 6.1.4

		and on commercially reasonable terms that encourage exploration and development of gas resources in this state		
	43.90.130(7)	(A) will propose and support the recovery of mainline capacity expansion costs, including fuel costs, from all mainline system users through rolled-in rates as provided in (B) and (C) of this paragraph or through a combination of incremental and rolled-in rates as provided in (D) of this paragraph);	2.4 2.4.1.3 2.4.1.1	6.1.3
	(B)	Will propose and support the recovery of mainline capacity expansion costs, including fuel costs, from all mainline system users through rolled-in rates; an applicant is obligated under this subparagraph only if the rolled-in rates would increase the rates (i) not described in (ii) of this subparagraph by not more than 15 percent above the initial maximum recourse rates for capacity acquired before commercial operations commence; in this sub-subparagraph "initial maximum recourse rates" means the highest cost-based rates for any specific transportation service set by the Federal Energy Regulatory Commission, the Regulatory Commission of Alaska, or the National Energy Board of Canada, as appropriate, when the pipeline commences commercial operations; (ii) by no more than 15 percent above the negotiated rate for pipeline capacity on the date of commencement of commercial operations where the holder of the capacity is not an affiliate of the owner of the pipeline project; for the purpose of this sub-subparagraph "negotiated rate" means the rate in a transportation service agreement that provides for a rate that varies from the otherwise applicable cost-based rate, or recourse rate, set out in a gas pipeline's tariff approved by the Federal Energy	2.4 2.4.1.3 2.4.1.1	6.1.3

		Regulatory Commission, the Regulatory Commission of Alaska, or the National Energy Board of Canada, as appropriate; or (iii) for capacity acquired in an expansion after commercial operations commence, to a level that is not more than 115 percent of the volume-weighted average of all rates collected by the project owner for pipeline capacity on the date commercial operations commence;		
	(C)	Will, if recovery of mainline capacity expansion costs, including fuel costs, through rolled-in rate treatment would increase the rates for capacity described in (B) of this paragraph, propose and support the partial roll-in of mainline expansion costs, including fuel costs, to the extent that rates acquired before commercial operations commence do not exceed the levels described in (B) of this paragraph;	2.4 2.4.1.3 2.4.1.1	6.1.3
	(D)	May, for the recovery of mainline capacity expansion costs, including fuel costs, that, under rolled-in rate treatment, would result in rates that exceed the level in (B) of this paragraph, propose and support the recovery of those costs through any combination of incremental and rolled-in rates;	2.4 2.4.1.3 2.4.1.1	6.1.3
	43.90.130(8)	State how the applicant proposes to deal with a North Slope gas treatment plant, regardless of whether that plant is part of the applicant's proposal, and, to the extent that the plant will be owned entirely or in party by the applicant, commit to seek certificate authority from the Federal Energy Regulatory Commission if the proposed project is engaged in interstate commerce, or from the Regulatory Commission of Alaska if the project is not engaged in interstate commerce; for a North Slope gas treatment plant that will be owned entirely or in part by the applicant, for rate-making purposes, commit to value	2.2 2.2.3.12	3.3 4.4. 4.4.2 4.4.3 4.4.4 4.4.5

		previously used assets that are part of the gas treatment plant at net book value; describe the gas treatment plant, including its design, engineering, construction, ownership, and plan of operation; the identity of any third party that will participate in the ownership or operation of the gas treatment plant, and the means by which the applicant will work to minimize the effect of the costs of the facility on the tariff.		
	43.90.130(9)	Propose a percentage and total dollar amount for the state's reimbursement under AS 43.90.110(a)(1)(A) and (B) to be specified in the license.	2.11	14
	43.90.130(10)	Commit to propose and support rates for the proposed project and for any North Slope gas treatment plant that the applicant may own, in whole or in part, that are based on a capital structure for rate-making that consists of not less than 70 percent debt;	2.2 2.2.3.5	9.6
	43.90.130(11)	Describe the means for preventing and managing overruns in costs of the proposed project, and the measures for minimizing the effects on tariffs from any overruns;	2.2.3.6 2.2.3.11	4.3
	43.90.130(12)	Commit to provide a minimum of five delivery points of natural gas in this state	2.1.1 2.2.3.9	4.3.9
	43.90.130(13) (A)	Commit to offer firm transportation service to delivery points in this state as part of the tariff regardless of whether any shippers bid successfully in a binding open season for firm transportation service to delivery points in this state, and commit to offer distance-sensitive rates to delivery points in this state consistent with 18 C.F.R. 157.34(c)(8); and	2.2.3.9	4.3.9
	(B)	Commit to offer distance-sensitive rates to delivery points in the state consistent with 18 C.F.R. 157.34(c)(8);	2.2.3.9	4.3.9
	43.90.130(14)	Commit to establish a local headquarters in this state for the proposed project	2.2.5	4.10
	43.90.130(15) (A)	Hire qualified residents from throughout the state for management, engineering,	2.3.4	5.3.1

		construction, operations, maintenance, and other positions on the proposed project.		
	(B)	Contact with businesses located in the state;	2.3.4	5.2 5.3.1
	(C)	Establish hiring facilities or use existing hiring facilities in the state;	2.3.4	5.2 5.3.1
	(D)	Use, as far as is practicable, the job centers and associated services operated by the Department of Labor and Workforce Development and an Internet-based labor exchange system operated by the state.	2.3.4	5.2 5.3.1
	43.90.130(16)	Waive the right to appeal the rejection of the application as incomplete, the issuance of a license to another applicant, or the determination under AS 43.90.180(b) that no application merits the issuance of a license;	1.13.7 Appendix D	1.1
	43.90.130(17)	Commit to negotiate, before construction, a project labor agreement to the maximum extent permitted by law; in this paragraph, “project labor agreement” means a comprehensive collective bargaining agreement between the licensee or its agent and the appropriate labor representatives to ensure expedited construction with labor stability for the project by qualified residents of the state;	2.3.3	5.3 Appendix MM
	43.90.130(18)	Commit that the state reimbursement received by a licensee may not be included in the applicant’s rate base, and shall be used as a credit against licensee’s cost of service;	2.2.3.10	4.3.10
	43.90.130(19)	Provide a detailed description of the applicant, all entities participating with the applicant in the application and the project proposed by the applicant, and persons the applicant intends to involve in the construction and operation of the proposed project; the description must include the nature of the affiliation for each person, the commitments by the person to the applicant, and other information relevant to the	2.8	2.0 2.1 3.3 4.6 5.0 5.3 5.3.1

		commissioners' evaluation of the readiness and ability of the applicant to complete the project presented in the application;		
	43.90.130(20)	Demonstrate the readiness, financial resources, and technical ability to perform the activities specified in the application by describing the applicant's history of compliance with safety, health, and environmental requirements, the ability to follow a detailed work plan and timeline and the ability to operate within an associated budget.	All of Section 2 and 2.9	11
		Required documents;		
		Signed application with corporate approvals	1.10.4 1.13.3	See application
		Signed certification, Appendix E	1.13.3	See application
		List of Applicant's Required and Additional Commitments		N/A
		Electronic Copy of Entire Application (On CD in PDF Print Ready Format)	1.5	CDs attached
		List of Data for Applicants to Provide in MS Excel Format, Appendix C (On CD in MS Excel)	2.10.1	Appendix NN
		Identification of Proprietary Information and Trade Secrets and summary of Information for Public	1.13.6	G-5, I, K. V, CC, DD, EE, FF, GG, II, JJ, KK

Applicant's Name ___________________________

APPENDIX B

Glossary of Selected Terms and Abbreviations

Glossary of Selected Defined Terms and Abbreviations

Term	Definition
AGIA	Alaska Gasline Inducement Act, AS 43.90.010 et seq.
ANGDA	Alaska Natural Gas Development Authority
ANGTA	Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. § 719 et seq.
ANS	Alaska North Slope
bcf/d	billion cubic feet per day
bcm	billion cubic meters
Bechtel	the Bechtel Corporation
BLM	U.S. Bureau of Land Management
DES	delivered ex-ship
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPC	engineering, procurement and construction
FEED	front end engineering design
FEIS	final environmental impact statement
FERC	Federal Energy Regulatory Commission
FNSB	Fairbanks North Star Borough
FOB	free-on-board
GCP	the proposed gas conditioning plant at Prudhoe Bay
GCP Participants	the entities that own and operate GCP
IEEJ	Institute of Energy Economics, Japan
JCC	Japan Crude Cocktail
License	the license awarded pursuant to AGIA
LNG	liquefied natural gas
LNG Facilities	the proposed liquefaction, and fractionation facilities, LNG and LPG storage, vessel loading and related facilities in Valdez
LPGs	liquid petroleum gases
m3	cubic meters
mbpd	million barrels per day
mmBtu	million British thermal units
mmta	million metric tons per annum
MOL	Mitsui O.S.K. Lines, Ltd.

MOL Companies	MOL and its subsidiaries BGT Limited and BLNG Inc.
NAESB	North American Energy Standards Board
NGA	the Natural Gas Act, 15 U.S.C. § 717 et seq.
NGLs	natural gas liquids
NPV	net present value
NSF	National Science Foundation
NTP	notice to proceed
NYMEX	New York Mercantile Exchange
Pipeline	the 806-mile overland natural gas pipeline extending from Prudhoe Bay to tidewater at Valdez proposed by the Port Authority
Port Authority	the Alaska Gasline Port Authority
Project	the project to develop, finance, construct and operate the Pipeline, LNG Facilities and GCP
RCA	Regulatory Commission of Alaska
RFA	Request for Applications
SIMP	stakeholder issues management plan
TAGS	Trans Alaska Gas System
TAPS	Trans-Alaska Oil Pipeline System
VLGCs	very large gas carriers
WTI	West Texas Intermediate
YPC	Yukon Pacific Corporation